

TVA AND THE CLINCH RIVER BREEDER REACTOR PROJECT

HEARING BEFORE THE SUBCOMMITTEE ON REGIONAL AND COMMUNITY DEVELOPMENT OF THE COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS UNITED STATES SENATE NINETY-EIGHTH CONGRESS

FIRST SESSION

APRIL 20, 1983

Printed for the use of the Committee on Environment and Public Works



U.S. GOVERNMENT PRINTING OFFICE
WASHINGTON : 1983

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WEDNESDAY, APRIL 20, 1983

U.S. SENATE
COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS,
SUBCOMMITTEE ON REGIONAL AND COMMUNITY DEVELOPMENT,
Washington, D.C.

The subcommittee met at 11 a.m., in room SD-406, Dirksen Senate Office Building, Hon. Gordon J. Humphrey presiding.
Present: Senator Humphrey.

OPENING STATEMENT OF HON. GORDON J. HUMPHREY, U.S. SENATOR FROM THE STATE OF NEW HAMPSHIRE

Senator HUMPHREY. Good morning.

Last year when funding for the Clinch River breeder reactor project was rejected in the House and sustained by only one vote in the Senate, the Conference decided to have the Department of Energy study how Federal appropriations for the project might be reduced by increasing the nuclear industry's share of the costs. The report was filed March 15 of this year and laid out several possible ways to finance the project with outside industry help.

Today's hearing concerns what the prospects are of TVA participating in alternative financing for the project. This topic is controversial. This Senator has opposed Federal funding of the Clinch River project for several years now. I still think it is an unnecessary and wasteful project that will do more harm to the cause of economical nuclear power than anything nuclear power's opponents might do.

Our concern today, however, is with the much narrower and more immediate matter of whether or not TVA will participate in increased utility financing for the project and, if so, in what way.

This fairly narrow inquiry is hardly academic, however. Indeed, what TVA has to say here could decide whether or not there will be any alternative financing for the project or, at the very least, what form it will take. TVA has been prominent in the Clinch River breeder reactor project. More than any other utility, TVA has lent its support to the project. TVA has lent, in addition, many of its personnel to the project's accounting free of charge. More important, an agreement with the Federal Government grants TVA the opportunity to operate the plant and to have the first right of refusal to buy the plant and its electricity. Certainly, what TVA chooses to do in arranging for alternative financing for the project

will set the standard for what other utilities will be willing to shoulder.

What must TVA be assured of before it participates in alternative financing? Must DOE assure TVA that it will buy all of the plant's output to power DOE's existing gaseous diffusion uranium enrichment plants? What specific actions, if any, will Congress have to take to secure TVA's support? Does any one of the several financing schemes suggested in DOE's March 15 report to Congress make more sense to TVA than any other? And, finally, which if any, of these proposals best serve the interests of the U.S. taxpayer?

The answer to the last question, of course, is the bottom line. Congress has been cautioned against back-door financing of Clinch River in the form of revenue guarantees and tax benefits for private investors. This has been the theme in two of the Washington Post's most recent lead editorials. If Congress tries to attract private investors to do Congress bidding by promising them guaranteed revenues and tax breaks in the future, Congress could easily end up forcing the taxpayer to pay more for the project, according to the Post, than if it simply appropriated money for the project outright.

We must avoid this. Indeed, today I am anxious that we learn as much as we can so that if Congress does proceed with some form of alternative financing, it does not become another burden on the taxpayer. If such burdens are to be avoided, it is essential that Congress know precisely how much sales of Clinch River electricity will be worth. If we can't know this, we must at least clarify what the uncertainties are to making such predictions.

Last Friday, I finally received a reply from the Department of Energy to an inquiry I made earlier along with five of my Senate colleagues concerning the Department's continued vagueness about the cost and source of plutonium needed to fuel the project. The cost, as we learned from the General Accounting Office's December 10, 1982, report, can be quite high. Indeed, if the plutonium comes from one of the surest sources—the defense production program—it could cost as much as \$5.1 billion to fuel the project over its lifetime.

DOE, of course, has not wanted to admit that it might have to use such expensive fuel for the project. Yet, what is disturbing is that DOE, even in its most recent reply, which I am releasing today, is unwilling to say where it will get this plutonium, and thus, identify exactly how much it will cost. Information of this sort is crucial if Congress is to make informed decisions about Clinch River and possible financing alternatives.

[Senator Humphrey's letter and the response from the Department of Energy follow:]

OPNDON HUNTERLEY
NEW HAMPSHIRE

United States Senate

WASHINGTON, D.C. 20510

February 17, 1983

The Honorable
Donald P. Hodel
Secretary of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Dear Mr. Secretary,

We are concerned over the Department of Energy's (DOE's) continued vagueness about the cost and source of plutonium fuel for the Clinch River Breeder Reactor project. As you know, late in 1981, Dr. Charles Gilbert, Deputy Assistant Secretary for Nuclear Materials, publicly testified that a shortfall in plutonium would occur by the end of the decade unless projected plutonium requirements are reduced or a new source of plutonium established.

Since then, we have learned that the L-reactor at Savannah River may not start operating until Spring, 1985. The DOE originally expected it to begin operating by October, 1983. We also have learned that a special DOE advisory panel recently urged the DOE to build a new materials production reactor to secure plutonium supplies for the 1990s. Because construction probably will not begin before 1985, the plant may not be completed until 1995, or later.

To stay within current cost estimates, however, the Clinch River Breeder Reactor will require substantial amount of plutonium fuel by 1987.

Also, the White House Office of Science and Technology recently announced that the U.S. has abandoned efforts to lease or buy plutonium from Great Britain.

Finally, we have learned the nuclear industry does not now believe the commercial reprocessing plant at Barnwell, South Carolina, will be completed in time to produce significant quantities of plutonium before 1987. Given the nuclear industry's reluctance during the past two years to invest in the Barnwell plant, there is growing doubt that it will ever operate.

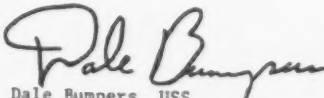
Because it could substantially affect the cost of the Clinch River Breeder Reactor, we would like to know when, and from what sources, the DOE intends to obtain the plutonium fuel.

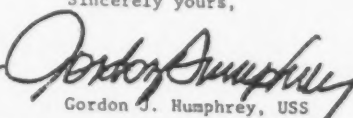
The Honorable
Donald P. Model
February 17, 1983
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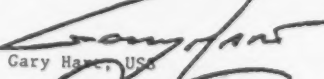
We have included a copy of the General Accounting Office's recent critique of the DOE's official position on this matter. We would appreciate your addressing this critique in your answer, which we look forward to receiving before the end of March.

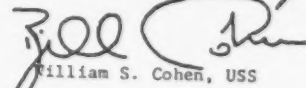
With warm regards, we are

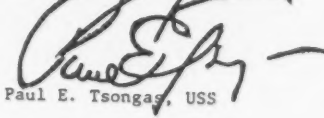
Sincerely yours,


Dale Bumpers, USS


Gordon J. Humphrey, USS


Gary Hart, USS


William S. Cohen, USS


Paul E. Tsongas, USS


Rudy Boschwitz, USS



THE SECRETARY OF ENERGY
WASHINGTON, D. C. 20585

April 15, 1983

Honorable Gordon J. Humphrey
United States Senate
Washington, D. C. 20510

Dear Senator Humphrey:

I am pleased to respond to the request contained in your letter of February 17, 1983, for information as to when, and from what sources, the Department of Energy (DOE) intends to obtain plutonium to fuel the Clinch River Breeder Reactor Plant (CRBRP) and to address comments concerning plutonium in the General Accounting Office (GAO) Report, GAO/RCED-83-74, dated December 10, 1982.

Plutonium fuel for the 5-year demonstration will be provided either from the DOE inventory, reprocessing of civilian Light Water Reactor (LWR) spent fuel, foreign sources, or some combination of these sources. This plutonium will be required in the time period 1987 to 1992.

DOE's inventory contains sufficient plutonium to fuel the CRBRP during the 5-year demonstration program. There would be no cost to the project for the use of plutonium in DOE's inventory. There are also the realistic alternatives identified above to provide the CRBRP plutonium in the event the Department elects to provide plutonium from some source other than DOE's inventory. A commitment to the ultimate source of supply would be premature at this time since the first plutonium will not be required for more than 4 years.

With respect to GAO's comments on the cost and source of plutonium for the CRBRP, although DOE does not plan to obtain plutonium by future production by the Office of Defense Programs, GAO explicitly assumed this was the only available domestic option. GAO appears to have discounted the alternatives of obtaining plutonium from foreign sources or purchasing the plutonium on the open market. The GAO analysis also considered reprocessing LWR spent fuel, apparently in the Office of Defense Programs' facilities, solely to obtain plutonium. Such an option is not under consideration by the Department. Plutonium is a byproduct of LWR spent fuel reprocessing, not, as GAO implies, the sole purpose of reprocessing. Based on incremental costs, we have projected \$7 a gram for processing fissile plutonium. In addition, the international market for fissile plutonium has been ranging between \$4 to \$6 a gram. It is important to point out that these prices reflect a limited market, primarily for French and German breeder reactors, but they do involve significant quantities. Although it would be risky to predict future plutonium prices based on today's market, the large costs mentioned in the GAO report seem unduly pessimistic. The key point is that until a strong market develops for plutonium it will probably be priced as a byproduct of reprocessing rather than a primary product.

Thank you for your interest in this matter.

Sincerely,

Donald Paul Hodel
DONALD PAUL HODEL

Senator HUMPHREY. We welcome as our first witnesses Mr. William R. Voigt, Jr., Deputy Assistant Secretary, Department of Energy; William F. Willis, General Manager of TVA who is accompanied by Lewis E. Wallace, Deputy General Counsel, TVA, Knoxville, Tenn.; and William Chandler, representing the Environmental Policy Center, Washington, D.C.

I will ask for the statements of each of you in the order printed on the witness list, starting with Mr. Voigt.

STATEMENT OF WILLIAM R. VOIGT, JR., DEPUTY ASSISTANT SECRETARY, DEPARTMENT OF ENERGY

Mr. VOIGT. Good morning. Thank you, Mr. Chairman.

I am pleased to appear before you to discuss certain aspects of the Department's uranium enrichment program. Specifically, I would like to address the marketing aspects of the uranium enrichment program and how this influences our position concerning the purchase of power for use by the program's gaseous diffusion plants. I would like to make a brief statement, and then I will be happy to answer any questions you may have.

The goal of the uranium enrichment program is to meet domestic and foreign utility and U.S. Government requirements for uranium enrichment services in the most economical, reliable, safe, and environmentally acceptable manner possible.

My office, the Office of Uranium Enrichment and Assessment, periodically estimates the domestic and non-U.S. nuclear electric generating capacity that will be served by the U.S. uranium enrichment complex.

Delays in nuclear programs, inflationary costs, and an economic slowdown worldwide have all contributed to excess enrichment commitments, large available utility-owned inventories, and associated financial burdens for the nuclear community. This situation, in combination with the pressures of a growing secondary market and aggressive actions by our enrichment competitors, has adversely affected the U.S. share of the enrichment market.

In contrast to its previous position of being the sole supplier of enrichment services in 1974, the U.S. share of the non-U.S. market has declined to about 30 percent today. A number of our foreign customers have switched from the United States to Eurodif, Urenco, and the U.S.S.R., and some new business has gone to these suppliers. During 1982, for the first time, a domestic utility terminated its contract with the United States in favor of lower priced separative work offered by a foreign supplier. To date, the total value of sales the United States has lost to foreign suppliers is over \$2 billion, with about \$0.5 billion in lost sales occurring during the last year.

Price has become the most important sales consideration to enrichment customers. The price advantage of \$30 to \$50 per SWU enjoyed by the United States in 1981 no longer exists. More and more frequently, sellers in the secondary market and our competitors have offered price guarantees at levels below the U.S. price. Their pricing strategies, the cost of producing separative work in DOE's existing power intensive gaseous diffusion plants, and the

fluctuating exchange rates have further aggravated the U.S. sales position.

To meet this challenge, we are taking a number of actions which are designed to enhance the marketing position of the U.S. uranium enrichment program. Specifically, steps are being taken to minimize the current selling price by reducing costs, optimizing enrichment production activities, and introducing new low-cost technology as rapidly as possible. The current long-range plan for uranium enrichment anticipates replacing high-cost gaseous diffusion capacity with advanced low-cost technologies as rapidly as possible.

To this end the gas centrifuge enrichment plant is being constructed on schedule and within cost. It is incorporating proven cost effective technology which will permit the United States to reestablish its competitive position in the marketplace. The advanced gas centrifuge and advanced isotope separation technologies, now being aggressively developed, will be available by the 1990's for DOE to choose for possible replacement of additional capacity in the higher product cost gaseous diffusion plants. If successful, these steps that I have outlined will maintain and eventually expand the U.S. sales base, thereby enabling significant benefits in terms of domestic employment, balance of payments, and a meaningful contribution to nuclear energy policies abroad.

In response to the reduced demand, the uranium enrichment program has no plans, at this time, to purchase all of the power that DOE now has under existing long-term power contracts through the early 1990's. As a result, the Department will be paying capacity charges for contract power not purchased from the Tennessee Valley Authority.

If we are to remain in a competitive position with foreign suppliers, we anticipate the need to shut down gaseous diffusion plant capacity in the early 1990's with a corresponding drop in uranium enrichment power requirements.

In summary, although our long-range enrichment strategy does not contemplate purchase of all existing contract power, existing DOE long-term enrichment contracts with a value of over \$100 billion will require production to meet these needs. To the extent that advanced technologies, such as that being incorporated into the gas centrifuge enrichment plant now under construction, and longer range technologies, such as the advanced isotope separation process, are not fulfilled, DOE will have no alternative but to buy additional power for the diffusion plants to fulfill our contractual obligations. In this situation, DOE would evaluate all power supply alternatives available.

This concludes my statement, Mr. Chairman, and I would be pleased to answer any questions you might have.

Senator HUMPHREY. Thank you, Mr. Secretary.

Mr. Willis, may we have your statement.

STATEMENT OF W. F. WILLIS, GENERAL MANAGER, TENNESSEE
VALLEY AUTHORITY, ACCOMPANIED BY LEWIS E. WALLACE,
DEPUTY GENERAL COUNSEL

Mr. WILLIS. Yes, Mr. Chairman, we are pleased to appear before this subcommittee to provide some information about TVA's participation in the Clinch River breeder reactor project.

I am General Manager of TVA and I have with me Mr. Wallace, our Deputy General Counsel. I would like my comments to focus on some general background of TVA's history in the project and the present status of our participation in the project.

In July 1973, a contract was executed among TVA, Commonwealth Edison, the Project Management Corporation, and AEC for the management, design, procurement, construction, and operation of the Clinch River plant. These contractual arrangements were amended in 1976 to reflect a substantially increased Federal role in project financing and management.

The Nation's electric power producers agreed to contribute approximately \$257 million toward the cost of this national energy project. TVA's share is \$21,700,000. We are obligated to make this contribution in 10 annual payments—each of \$2,170,000. We have made five annual payments. Beginning in 1977, BRC deferred the remaining five payments. But TVA—like other contributing electric systems—has a continuing obligation to make the payments when called for by BRC. BRC plans to call for the collection of one payment that will be due in December 1983. TVA also is obligated to contribute 2 million dollars' worth of services to the project.

Under the 1976 amended agreement, TVA has agreed to be a directly participating member of the project team. In addition to a general good faith obligation to assist the project, we have agreed to lend employees to the project and are a joint applicant with DOE and PMC for the required NRC license. DOE reimburses all of TVA's project-related expenses.

TVA is obligated to purchase all of the plant's electrical output for the 5-year demonstration period, and provide plant energy requirements during periods of no generation. For power delivered to TVA, we will pay to the project an amount equal to the out-of-pocket costs we otherwise would have incurred for a comparable amount of electric energy.

In addition to buying the energy, TVA will use its employees to conduct preoperation test programs, and thereafter to operate and maintain the plant during the demonstration period. This will be done on a cost reimbursable basis under an agreement to be negotiated between TVA and DOE.

Finally, TVA has an exclusive option to buy the plant. In view of TVA's projected system capacity needs, which I will discuss later, TVA probably will not exercise its option.

Based on the high growth forecast, the earliest TVA would need capacity is 1994. If the low growth forecast prevails, TVA may not need to build additional generating capacity until well after the year 2000. Actual loads are likely to be closer to the low forecast than the high forecast.

TVA currently has several options to meet its future capacity needs as they develop. Many uncertainties influence the cost and

timing of new capacity, but in any event the earliest that TVA would need to face a decision on new capacity to meet growth associated with its high load forecast would be 1986 or 1987. Lower load growth than projected in TVA's high forecast could postpone any decision on new capacity until 1990 or later. In light of this, TVA is in no position to buy some or all of the Clinch River plant's capacity.

Although TVA itself could not use the plant's capacity in the foreseeable future, we certainly could make available TVA's transmission system to transfer, or wheel, the plant's output to another electric system in need of such capacity. The development of TVA's 500-kilovolt transmission system, together with the interconnections to neighboring utilities, has progressed to the extent that we can exchange large amounts of power in most directions. We would not expect to experience technical difficulties in transmitting power generated at the Clinch River plant to most of our neighboring utilities. The charge for such wheeling service would be based on recovering TVA's cost for the service provided.

While TVA would not be a market for the project's capacity, we are ready to support the project in the following specific ways assuming that congressional authorizations are sufficient to keep TVA financially whole, both as to finances and liabilities:

First, we would contract on a full cost reimbursable basis, including appropriate indemnification provisions, to operate the plant for whatever entity should become its owner. The contract would have to include appropriate arrangements to assure that TVA's operator obligations would not impair our continuing ability to operate the TVA power system safely and economically.

Second, we would contract to continue to buy the energy from the plant on an avoided incremental cost basis, excluding capacity charges.

Third, we would contract to wheel the project's electricity over the TVA transmission system to purchasers outside the area served by TVA with reimbursement based on appropriate terms and conditions.

Fourth, we would be happy to lend our facilities and experience to the plant's owner on a full cost reimbursable basis, including appropriate indemnification provisions, in any other way that might help the project.

Senator HUMPHREY. I don't believe we have a copy of your statement. I will ask staff to secure a copy now and make copies for interested parties.

Thank you for your statement.

Mr. Chandler.

STATEMENT OF WILLIAM U. CHANDLER, DIRECTOR, ENERGY CONSERVATION PROJECT, ENVIRONMENTAL POLICY INSTITUTE AND CENTER

Mr. CHANDLER. Thank you.

I am Bill Chandler, director of the energy conservation project, Environmental Policy Institute Center. I believe you have several copies of my prepared statement so I will summarize that at this time.

The proposals to fund Clinch River by selling the power it would generate and ultimately the plant itself all depend on forecasts of future electric power demand. This reminds me of the advice of Alvin M. Weinberg who as my former employer once warned me, "Never make a prediction until you are very old: you might live to see it not come true."

Fortunately, the Tennessee Valley Authority projects electric power demand in its service area with one of the most sophisticated sets of models used in the utility industry. TVA's demand projections and others for the entire southeast region show that DOE would probably be unable to sell Clinch River power and/or the plant should it be built.

The DOE Clinch River proposals hinge on being able to sell power to TVA, other utilities in the southeast, or to the Government itself for use in uranium enrichment. In fact, none of these are likely to be customers for additional electric supply for the rest of the century, for the following reasons:

First, TVA's power forecast indicates a 90-percent probability that TVA will not need any new capacity through the end of the century.

Second, a congressional research study shows that it is highly improbable that the southeast region will need additional powerplants through 1995.

Third, the Government uranium enrichment facilities have already contracted for 6 to 20 billion kilowatt-hour per year more than TVA expects them to take in the year 2000. This could mean that DOE will already be paying for tens of millions of dollars' worth of power it will be unable to use.

The likelihood that there will be no market for Clinch River power is so great that it undermines a fundamental requirement set by the drafters of alternative financing plants: "To establish a stable and predictable financial basis for cost-effective completion of the plant."

Additionally, basic assumptions made by the BRC and DOE in their background analyses, including the future price of electricity in the Southeast, are at best inconsistent with published DOE estimates and, at worst, invalid.

In my written statement, I elaborate on the following specific points:

First, TVA currently owns approximately 32,000 megawatts of installed electric generating capacity. By 1988, TVA will have completed an additional 5,000 megawatts now under construction, for a total of 37,000 megawatts of power generation capacity. But peak electric demand will be far lower. TVA, in fact, estimates that there is only a 10-percent chance that demand will exceed 34,700 megawatts in 1995. Thus, TVA will probably have 2,300 megawatts of excess capacity in 1995, the year in which the Breeder Reactor Corporation and the Department of Energy propose to sell the CRBRP. There is very little chance that TVA would want to buy the breeder's 330 megawatts.

Second, even if TVA did require new capacity, TVA would first be obligated to complete deferred facilities. TVA has deferred completion of 5,324 megawatts, plants on which TVA has already spent approximately \$2.5 billion.

Third, the Department of Energy study of alternative financial mechanisms for the CRBR implies that new capacity totaling 16,000 megawatts will be required in the Southeast Electric Reliability Council [SERC] region by 1995, and that Clinch River could be used to help satisfy this demand. But a recent study by the Congressional Research Service projects that the Southeast region [SERC] will have a reserve electric capacity margin of 35 percent in 1990, and 26 percent in 1995. The latter amounts to 6 percent more capacity than is commonly considered "adequate," and 11 percent more than is considered "acceptable".

Fourth, DOE also estimated that Clinch River power would be worth about 15 cents per kilowatt-hour in 1991. This estimate may be misleading. The estimate is 50 percent higher than DOE published cost estimates for coal-fired power coming on-line in the Southeast in the 1990's.

Revenue projections made by the Department of Energy and the Breeder Reactor Corporation on the basis of sale of electricity and/or the CRBRP after the initial 5-year demonstration phase of the plant are extremely tenuous. Revenue estimates have been based on levels of electric capacity demand in the Southeast that are improbable, and on electric price levels that are inconsistent with published DOE estimates.

The DOE/BRC analyses, therefore, fail to meet their own basic criterion, to establish a stable and predictable financial basis for cost-effective completion of Clinch River. A shortfall in CRBRP revenues would be likely if the plant were built, and these would have to be made up by Federal appropriations.

Senator HUMPHREY. Thank you.

The essence of the situation is that proponents of the Clinch River suggest that in order to comply with the conference-mandated requirement of attracting private investment, that such private investment can be sold on one or more bases; namely, that DOE needs the output of Clinch River for the enrichment program; second, that TVA could possibly use its Clinch River output, that is already being refused by Mr. Willis; or third, that TVA would wheel that power, and Mr. Chandler has contended there doesn't seem to be any market for that either.

Let us focus on each of those elements, beginning with Deputy Assistant Secretary Voigt, and focusing on the matter of the DOE and uranium enrichment program and what part of the output the Clinch River might play in that program.

Mr. Voigt, to begin with, what is the largest component of the cost of enriching uranium?

Mr. VOIGT. Mr. Chairman, the current price for enrichment services is \$138.65 per separative work unit; about 50 percent of that price is directly attributable to power costs.

Senator HUMPHREY. The biggest single cost in the component in the total cost is electricity?

Mr. VOIGT. That is correct.

Senator HUMPHREY. The Department of Energy buys electricity both from TVA and from private utilities, is that not so, in the enrichment program?

Mr. VOIGT. That is correct.

Senator HUMPHREY. It buys power from TVA for DOE facilities in Oak Ridge and in Paducah; is that correct?

Mr. VOIGT. TVA supplies all the power to the Oak Ridge facility and a major fraction of the power to the Paducah facility; the other fraction is furnished by a private utility.

Senator HUMPHREY. For your Portsmouth facility, you buy your electricity from private utilities, non-TVA sources?

Mr. VOIGT. It is a consortium of private utilities.

Senator HUMPHREY. They do not draw their power from TVA?

Mr. VOIGT. That is correct.

Senator HUMPHREY. Can you give us a comparison of the costs in buying electricity from uranium enrichment firms, TVA versus the consortium?

Mr. VOIGT. Yes, sir. I would like to relate this to our fiscal year 1984 budget now before Congress. TVA in that power budget is 58.2 mills per kilowatt-hour, OVEC is 29.6 mills per kilowatt-hour, and EEI is about 27.9 mills per kilowatt-hour.

I must admit those numbers do reflect demand charges that we are paying to TVA. In the absence of paying any demand charges, the mills per kilowatt-hour for TVA will be on the order of 41 mills per kilowatt hours.

Senator HUMPHREY. Still more expensive?

Mr. VOIGT. Yes.

Senator HUMPHREY. As we know from Mr. Willis' testimony, TVA doesn't give anything away and I am glad to know that. You are having to pay for electricity that you are not using.

What is the Department of Energy, doing to reduce the electricity cost in their enrichment of uranium?

Mr. VOIGT. Well, in the longer term, Mr. Chairman, what we are attempting to do is to displace diffusion plant capacity with lower cost, less energy intensive advanced technology, such as the gas centrifuge enrichment plant—I touched upon that in my statement. The Gas Centrifuge enrichment plant, for example, only uses about 4 percent of the equivalent amount of energy to produce the same amount of separative work that a diffusion plant does. Hence, from that standpoint it is very energy efficient.

Senator HUMPHREY. What are your plans regarding the gaseous diffusion plants at Oak Ridge and Paducah once GCEP comes on line?

Mr. VOIGT. We now have under way, Mr. Chairman, a detailed study for shutting down diffusion plant capacity. This study will be completed in the summer of this year. To the extent that we are allowed to complete GCEP with a full eight process buildings and incorporate the advanced gas centrifuge technology we can shut down diffusion plant capacity and displace it through this centrifuge plant.

We are also analyzing as to whether the other advanced technologies, such as advanced isotope separation, have the technical capability as well as economic capability of producing enriched uranium. It is too early at this particular point in time to say whether they do or not.

In the event either the advanced centrifuge or advanced isotope separation, programs are successful, we will shut down further diffusion plant capacity and thus be more competitive.

Senator HUMPHREY. Is it pretty safe to conclude that if you are successful in building the gas centrifuge enrichment plant in Portsmouth on a full case, it will be desirable to shut down the gas centrifuge plant in Oak Ridge and Paducah?

Mr. VOIGT. That is correct, Mr. Chairman.

Let me put it in perspective. If we were to supply all of our enrichment contracts just by utilizing the three existing diffusion plants fully powered, what we will be doing is pricing ourselves out of the enrichment market. We have to bring on new technologies or we are out of the picture.

Senator HUMPHREY. So it is probable at this point that Oak Ridge and Paducah will be shut down?

Mr. VOIGT. I wouldn't want to say which of the three sites.

Senator HUMPHREY. One or both over time will have to be shut down.

Mr. VOIGT. Maybe all three for that matter.

Senator HUMPHREY. Very well.

How much longer, then, do you anticipate buying power from TVA at rates higher than OVEC and EEI? For the benefit of those of us that do not know what that stands for, will you tell us?

Mr. VOIGT. EEI is Electrical Energy Inc. OVEC is Ohio Valley Electric Corp.

Senator HUMPHREY. How much longer do you anticipate premium rates of TVA when you can buy cheaper power?

Mr. VOIGT. Our present operating plan, Mr. Chairman, maintains three diffusion plants into the 1990's, however, not at the power levels that we now have under contract. We have already given notice to the TVA that we will not be picking up 2,000 megawatts of the roughly 4,500 megawatts we now have under contract in the late 1980's and early 1990's.

Senator HUMPHREY. You mentioned that DOE is losing business. Have there been cancellations in long-term contracts as a result of competition from secondary enrichment markets?

Mr. VOIGT. Not in terms of long-term contracts, Mr. Chairman. We have one possible contract terminating which may go to a foreign supplier. That contract is with the South Carolina Electric & Gas Co. Most of the sales that are now taking place are from what we call a secondary market. This is where utilities have separative work above and beyond their needs. They are selling the excess separative work in the secondary market, in what I call a distressed market at depressed prices, whatever they can get for it. It is being very heavily discounted.

Senator HUMPHREY. Is that a trend you see continuing for some time?

Mr. VOIGT. Unfortunately, that is true, Mr. Chairman. We now project a sizable secondary market until the late 1980's.

Senator HUMPHREY. So it underscores once again the point that if DOE is to remain competitive that it must secure its electricity from less expensive sources than TVA.

Mr. VOIGT. And less energy expensive means of doing it too, yes.

Senator HUMPHREY. What demand for electricity in your enrichment program do you forecast for the period 1995? Is it higher than today? Lower?

Mr. VOIGT. It is higher than what we have today, Mr. Chairman. I can give you that number. Right now we are forecasting that in 1995 that we will be requiring of the order 3,800 megawatts to the three sites. Right now we are operating the plant at about 2,660 megawatts.

Senator HUMPHREY. You intend to be operating the three sites as late as 1995?

Mr. VOIGT. Within the framework of our current operating plan. Again that largely hinges on what happens to the gas centrifuge enrichment plant and also what happens with the advanced technologies.

Senator HUMPHREY. What about for the period beyond 1995, say 1995 to the year 2020?

Mr. VOIGT. Again, that really depends, Mr. Chairman, on whether there is increase in nuclear power growth both domestically and worldwide, and what fractions of that total demand we might capture. Right now I would say we were projecting at least that we would be staying in the order of 3,800 megawatts or less.

Senator HUMPHREY. In any case, you are projecting a higher requirement for electricity with respect to the Portsmouth facility. With respect to your Portsmouth facility, do you anticipate a higher requirement for electricity in 1995 than today?

Mr. VOIGT. No, sir. But we won't know sure until the results of the shutdown study are known. The new centrifuge facility will only require 135 megawatts to operate.

Senator HUMPHREY. By 1995, what percentage of your enrichment will be taking place at Portsmouth versus your other plants?

Mr. VOIGT. By 1995 one-half. We are projecting right now that the needs are of the order of 26 million separative work units, one-half of that will be coming from Portsmouth.

Senator HUMPHREY. And you anticipate no difficulty at all in securing new electricity?

Mr. VOIGT. We will be negotiating with OVEC and EEI in the near future, in terms of looking at the longer range projections we might foresee.

Senator HUMPHREY. With respect to OVEC and EEI, generating capacity, you anticipate any difficulty in being served?

Mr. VOIGT. No, sir, we do not at this particular point.

Senator HUMPHREY. Then from the enrichment standpoint, do you see any need to buy all of the electrical output as has been suggested by some proponents for alternative financing for Clinch River?

Mr. VOIGT. I think it would be fair to say, Mr. Chairman, again this all hinges on the fact of whether we go forward with advanced technologies or we do not.

Senator HUMPHREY. Can you be more specific? Is that specifically GCEP?

Mr. VOIGT. That is a big factor.

Senator HUMPHREY. What size factor?

Mr. VOIGT. Right now we are forecasting 13 million SWU production out of GCEP. We have underway technologies that could possibly increase that 13 to 26 million SWU production.

In the event that were to happen, as I mentioned earlier, our total demand against the system is 26 million SWU's. So hence under that scenario, GCEP could handle our total production load.

Senator HUMPHREY. If you had the full eight-building size facility at GCEP, would there be any necessity to buy all of the output of Clinch River?

Mr. VOIGT. No, sir.

Senator HUMPHREY. Would there be the necessity to buy any output of Clinch River under that scenario?

Mr. VOIGT. Under advanced technology that I mentioned, no, in fact there would be no need to buy power for any of the three diffusion plants.

Senator HUMPHREY. If you have the full GCEP facility, there will be no need to buy electricity for any of the gaseous diffusion plants, Oak Ridge, Paducah, and presently Portsmouth?

Mr. VOIGT. That is correct, Mr. Chairman. Full GCEP and advanced technology.

Senator HUMPHREY. Your operating plan projects uranium enrichment demand for 1995 of 26.3 million SWU's, if GCEP is built to 2.2 million SWU's and you buy all the power contracted to buy from TVA, you will have the capacity of over 27 million SWU's, doesn't that indicate that the eight-building project is excessive?

Mr. VOIGT. No, sir, it doesn't. What we are really saying is that there is a requirement to service our existing contracts at the cheapest possible cost. In attempting to do that with our existing three diffusion plants, as I mentioned earlier, we will price ourselves out of the marketplace. It is only through the deployment of these new technologies such as we are envisioning and incorporating into GCEP that we can effectively compete in the marketplace.

Senator HUMPHREY. Let's turn the heat on Mr. Willis, or the light as it may be.

Mr. Willis, you are general manager at TVA since 1979. You have been with the TVA in positions of high responsibility for 23 years.

Mr. WILLIS. That is correct.

Senator HUMPHREY. TVA recently canceled construction of a number of nuclear powerplants, is that not correct? And, if so, will you go into that in some detail.

Mr. WILLIS. Yes, sir. A few years ago, we had a total of 18 units under some phase of operation and construction.

Senator HUMPHREY. How many?

Mr. WILLIS. Seventeen. Today we have five nuclear units operational and four that are under active construction that we intend to complete to make a total of nine units. We have three units in a deferred status.

Senator HUMPHREY. Four are deferred?

Mr. WILLIS. And five canceled.

Senator HUMPHREY. Forever?

Mr. WILLIS. Yes.

Senator HUMPHREY. In the foreseeable future.

What accounts for that change in plants?

Mr. WILLIS. Basically the change in load forecast for the future. The projections that were made in the late 1960's and early 1970's that brought about the commitment to build these nuclear units

were based on a forecast of 6 to 7 percent a year load growth. Of course that picture has changed drastically, and our forecast for load growth in the future now is ranging somewhere between a low side of less than 1 percent a year and a high side of 2½ percent. The need for capacity has changed drastically, and we had to decide how to respond, taking into account the financial impact on the system.

Senator HUMPHREY. That decision no doubt flowed in part at least from section 12 of the Tennessee Valley Authority Act which states in part that power from TVA plants is to be sold to consumers at a price that is not in excess of what is "deemed to be just, reasonable, and fair by the Board." And, as I understand it, board members in the past have publicly argued that this phrase means that TVA must supply electricity to its consumers at the lowest possible cost, is that all correct?

Mr. WILLIS. Yes, sir. All of our power decisions are driven by our desire to assure low costs for our consumers.

Senator HUMPHREY. According to Modification No. 1 to TVA original agreement, this is somewhat repetitious but I want to touch upon it again. Modification No. 1, the TVA has the option to purchase the Clinch River plant, after the first 5 years of the plant's operation. Does TVA intend to exercise this option?

Mr. WILLIS. At this time we do not. We do not forecast a need, as I mentioned earlier in my statement, for capacity in that time frame, so we do not contemplate exercising that option.

Senator HUMPHREY. According to section D-11.1 of the same agreement, TVA agreed to take "for its system all of the electric output of the plant and pay for it" on an incremental or avoided cost basis.

Is this provision still binding?

Mr. WILLIS. Yes, it is for the five-year demonstration period.

Senator HUMPHREY. So you are bound to purchase the output of Clinch River for the first years, is that correct?

Mr. WILLIS. That is correct.

Senator HUMPHREY. On what basis will you pay for it?

Mr. WILLIS. We will pay for it on the highest avoided cost basis as provided in the contract. That simply means we pay a price that is equivalent to whatever energy cost is displaced in the system. In other words, if one of our fossil plants happened to be supplying the highest cost energy, the avoided cost would be the cost of running that plant. Fixed costs or the cost, of building that plant would not be considered.

Senator HUMPHREY. According to our understanding of matters, is that avoided cost likely to be more or less than the actual cost of producing electricity at Clinch River?

Mr. WILLIS. Since this avoided cost does not include any capacity cost, it would be less. If you figure the total cost of producing power at the Clinch River plant, including capital investment that cost will be higher than what we are obligated to pay under our contract.

Senator HUMPHREY. In other words, you would be getting a bargain.

Mr. WILLIS. Well, we are right back in the posture of protecting our customers by buying the power at the lowest avoided cost.

Senator HUMPHREY. Like the way you do business. You don't give away anything but you are perfectly willing to take a bargain. That is good business. I don't know how good it is for the taxpayer.

Well, you said pretty clearly at the outset in your testimony that TVA does not need, whether it is bound to take it or not, does not need the output of Clinch River.

Mr. WILLIS. Our current forecast, indicates that we will not need that additional capacity in that time range.

Senator HUMPHREY. What are you going to do with it?

Mr. WILLIS. During the 5-year time that we have it on demonstration, it will be folded into our system and whatever load that displaces on the system will just be idle load that we won't use. Our ratepayers are made whole because they pay no more than they would otherwise.

Senator HUMPHREY. Are you going to pass along the discount to your customers?

Mr. WILLIS. There is no discount price in that. All of our power rates are based on a cost basis.

Senator HUMPHREY. But you said that the power from Clinch River will be less expensive than it would have cost you if you built something else.

Mr. WILLIS. But, if we have to make a coal plant idle or put it in standby, we still have investment in that coal plant, and we have to pay for it. You cannot idle fixed costs.

Senator HUMPHREY. Is TVA interested in Clinch River under any of the proposed alternative financing schemes?

Mr. WILLIS. I have mentioned, we will certainly meet our obligations. Under the financial schemes it was not contemplated that TVA would have any particular role.

Senator HUMPHREY. Are there any of those schemes that are more attractive to TVA than others?

Mr. WILLIS. I think that the attractiveness to TVA is a point I wouldn't want to address because the financial community and the Department of Energy is where the question lies in my mind. What is attractive to the financial community in making these sort of arrangements is something unique to them, and it does not impact TVA.

Senator HUMPHREY. Would you care to postulate any criteria for alternative financing schemes for Clinch River that would make it attractive to TVA?

Mr. WILLIS. Well, as I mentioned earlier, since we do not anticipate having any need for capacity in that time frame, I can't fathom any financial arrangements that would be meaningful to TVA. We have to make commitments for capacity based on what is the lowest cost to get capacity whenever we need it. I can't comment on the nature of that without seeing the specifics of how it might impact TVA.

Senator HUMPHREY. Let's suppose TVA were interested in participating in an alternative financing scheme, one kind or the other, where would TVA obtain the money to buy in?

Mr. WILLIS. Well, for normal operations and providing for capacity or expansion in the future, we only have two sources of money. One is power revenues and the other is the sale of power revenue

bonds. When we make decisions about the future capacity, these are the only places we have to look for financing.

Senator HUMPHREY. There is, of course, one other convenient source of financing for TVA and any other agencies and that is the Federal Financing Bank and, of course TVA has availed, as an outfit always on the lookout for bargaining, has availed itself of the Federal Financing Bank, has it not?

Mr. WILLIS. Yes, we have. The Federal Financing Bank is a mechanism by which we sell our power revenue bonds. We began using the Federal Finance Bank a number of years back at their suggestion, and we are continuing to use it. That is how we sell our power revenue bonds today. But they are backed by the ratepayers of TVA and not the taxpayers of the Nation. The FFB is not a source of funds in addition to system revenues and system borrowings. It is merely a source of borrowing on the same general terms as would be available if TVA borrowed directly now, as it has in the past, from private lenders.

Senator HUMPHREY. Before this arrangement you sold your bonds on the open market?

Mr. WILLIS. That is correct.

Senator HUMPHREY. And now you sell them to the Federal Financing Bank and, have you experienced a lower financing cost by this latter arrangement versus the former?

Mr. WILLIS. It can be argued that we get a better, a few basis points better, by going through that mechanism. We don't know since we have not placed any bonds on the market to make that comparison. We anticipate the probability it would be.

Senator HUMPHREY. That is a pretty safe assumption, I think.

I would like to make the point for those who suggest alternative financing facilitated by the Federal Financing Bank that constitutes nothing less than back-door financing by the Federal Government of Clinch River. Front door is you appropriate the money. The back door—which of course we have to borrow anyway, selling debt instruments—the back door is financing through the Federal Financing Bank which is off budget but has the same effect on the economy. The Federal Financing Bank has to borrow money and it has the same effect even though it might not show up on the ledger.

So that I hope the proponents of alternative financing will not suggest that somehow this is a less burdensome solution on the American people than up-front financing by the Congress.

Assuming that TVA wanted to participate in alternative financing arrangements, would you be willing to hike your rates, let's say to residential customers?

Mr. WILLIS. Certainly not. Any decisions on new capacity would be controlled by the need to look for the lowest possible cost that might impact our consumers. We do not make any decisions to make one capital expansion or another based on classes of customers we might impact. Our cost-of-service way of doing business is standard and well known. It is the way we always do business; it is the cost of service.

Senator HUMPHREY. Are you permitted to include CWIP-hold to your rate charges to any construction work in progress charges?

Mr. WILLIS. We have some of the interest during construction that goes into capital. In fact though, all of the interest that we pay on borrowed funds must go into the current rate base. We are required by our statute and by our bond covenants to include in the rate base all interest we pay on all indebtedness each year.

Senator HUMPHREY. You routinely include CWIP in your retail. How about wholesale, did you include construction charges in wholesale sales?

Mr. WILLIS. Yes. It is in our entire rate base.

Senator HUMPHREY. And that is not just for residential but for business?

Mr. WILLIS. Yes.

Senator HUMPHREY. Would you be willing to sell, again assuming you wanted to do this, participate in alternative arrangement, sell TVA bonds in the open market?

Mr. WILLIS. To finance this project?

Senator HUMPHREY. Yes.

Mr. WILLIS. As I mentioned, we have no intention to assume ownership of this project at this time. Only if we decided TVA needed additional capacity would we be willing to consider making a capital investment in the project.

Senator HUMPHREY. Does TVA consider Clinch River to be primarily a research and development project?

Mr. WILLIS. At this time, yes. A number of years back there was a more immediate need to the utility industry, but now we consider it as a part of a long-range R&D project that we contribute to and fund just like we do a number of R&D projects in our system. That is the way our funding is treated. It goes into the system as part of our R&D costs.

Senator HUMPHREY. Your involvement with Clinch River so far has been on an R&D basis?

Mr. WILLIS. That is correct.

Senator HUMPHREY. In much the same way you are involved with R&D on coal and conservation.

Mr. WILLIS. That is correct.

Senator HUMPHREY. Where does TVA get the money to invest in coal R&D and conservation R&D and Clinch River R&D?

Mr. WILLIS. From our ratepayers.

Senator HUMPHREY. You get it from your ratepayers?

Mr. WILLIS. Yes, sir. We have a standard policy at TVA addressing R&D. We look at a range between 1 and 2 percent, up to 2 percent of our total budget, that we are willing to invest in appropriate R&D projects.

Senator HUMPHREY. Would you be willing to reduce your R&D in the area of coal and/or conservation in order to increase your R&D contribution to Clinch River?

Mr. WILLIS. We think our spread of R&D is appropriate at this time.

Senator HUMPHREY. Is TVA considering an investment in a reactor project called PIUS to protect safer reactors?

Mr. WILLIS. We are aware of that technology, and have had some discussions with the people involved. We are interested in that, along with several other new technologies and nuclear reactor de-

signs. We have been keeping up with the technology but we have not made any major investment.

Senator HUMPHREY. Where would you get the money if you choose to get that investment?

Mr. WILLIS. It would come from our ratepayers.

I might want to qualify that last statement. If Congress would decide to get involved in funding with us, we would certainly entertain the thought of that scenario.

Senator HUMPHREY. We know you are always on the lookout for a bargain. So am I.

Mr. Willis, do you consider the projects by DOE and BRC that Clinch River electricity might be worth 14 to 16 cents per kilowatt hour in the 1990's to be reasonable?

Mr. WILLIS. I am only qualified to comment on how much it would be worth to us; how much it is worth on the open market I would leave to the people who really looked into the matter—that is, to the task force group.

We didn't participate in that. We only participated in calculating what it may be worth on TVA's system at that time. They did give us some numbers to look at regarding the present worth, but all we did was to run it through our system. So I couldn't testify to the validity of those numbers.

Senator HUMPHREY. Under section D-1032 of modification 1 of the original agreement TVA reached, TVA was supposed to calculate the imputed value of the Clinch River plant and use this value to compute the amount TVA might pay for the plant should it choose to purchase it.

Are you familiar with the letter sent to Mr. Gordon Chipman by Lynn C. Maxwell, your chief of planning?

Mr. WILLIS. Yes, I have seen that letter.

Senator HUMPHREY. That analysis by Mr. Maxwell sent to Mr. Chipman assumed that the plant would operate at 80 percent capacity factor, that further the reprocessing of the plant's fuel would be free and that the electricity would be sold not at avoidance cost but at wholesale rates.

DOE instructed Mr. Maxwell to make these assumptions in his calculations back in 1981.

Do you think these will be reasonable assurances for Mr. Maxwell to make if he was making calculations for TVA exclusively?

Mr. WILLIS. I think we would have to defer to the Department of Energy to get what the load factor would be for the plant.

We would have to use those numbers.

I think the discount rate at that time was probably appropriate. As it is shown in this letter, we merely ran some calculations based on the factors that they gave us and that was the full extent of our participation in it.

Senator HUMPHREY. Let me repeat again.

If Mr. Maxwell were making projections for TVA exclusively, do you think that it would be reasonable for him to assume in those projections that the Clinch plant would operate at 80 percent capacity factor, the reprocessing of the plant's fuel would be free and the electricity would not be sold at avoidance cost but wholesale rates?

Mr. WILLIS. The capacity factor is again a matter that I think you would have to have consultation with the technical community.

Senator HUMPHREY. Let's drop that one.

Mr. WILLIS. I couldn't make any comment on getting the fuel free. We have to pay for our fuel.

Senator HUMPHREY. You are pretty good at getting bargains, do you think they can get it reprocessed free?

Is that a reasonable assumption?

Mr. WILLIS. I couldn't comment on that.

Senator HUMPHREY. Mr. Maxwell presented you with projects based on the assumption that Clinch River fuel would be reprocessed free, would you consider that a prudent projects?

Mr. WILLIS. I think I would have a question about it.

Senator HUMPHREY. You would have a question about it?

Mr. WILLIS. If it were a TVA facility.

Senator HUMPHREY. I understand with that caveat, of course.

What about the assumption that electricity would be sold not at avoidance cost but at wholesale rates?

Mr. WILLIS. I think the assumption would be based on some utility needing capacity. If that is the case, that would be a valid statement.

Senator HUMPHREY. Do you know of any adjacent utility that needs the power?

Mr. WILLIS. Sir?

Senator HUMPHREY. Do you know of any adjacent utility or consortium that needs the power?

Mr. WILLIS. Today?

Senator HUMPHREY. Yes.

Mr. WILLIS. I am not aware of any today.

Senator HUMPHREY. How about by 1995. You sell electricity, you must be aware of what the surrounding needs are.

Mr. WILLIS. There is a possibility there could be needs in the 1995 timeframe.

Senator HUMPHREY. Sufficient to use up all of the Clinch River output?

Mr. WILLIS. Yes, that is just a small fraction of the power net of the contiguous utilities around us and I think that is feasible.

It depends very much on the growth of the economy, what happens as a result of that. But it could be done, it could be needed.

Senator HUMPHREY. All right. Again, bearing in mind that Mr. Maxwell was instructed by the Department of Energy to make those liberal assumptions, is it strange, in your mind, that Mr. Maxwell was able to say that the present worth of Clinch River's life revenues was \$542 million and now DOE is telling us that these revenues might be worth \$900 million.

Mr. WILLIS. I think there may be some apples and oranges in those figures. One is the present worth of net value based on 1981 figures and I understand that the \$900 million figure is based on a 1992 timeframe. That I think could explain the difference.

Senator HUMPHREY. You are talking about the difference in the value of current dollars versus 1995 dollars.

Mr. WILLIS. I think they cast theirs in the 1992 timeframe, and ours was based on a 1981 timeframe.

Senator HUMPHREY. Well, that is an apples and oranges situation.

Let me ask you, Mr. Willis and likewise Secretary Voigt, to provide us the value of the life time Clinch River output in 1981 dollars versus 1995 dollars, if that is what was used to arrive at the \$900 million figure.

Mr. WILLIS. That is based on the assumptions given us that are in this document you are talking about.

Senator HUMPHREY. Could you do it both ways, please?

Mr. WILLIS. Another thing, in answering that letter, we used our system average cost and did not include a capacity value. Would you want that with the capacity value also?

Senator HUMPHREY. We will have to iron out the details with the staff.

Mr. WILLIS. We would be glad to.

Senator HUMPHREY. Thank you.

We are almost finished.

How much do you think the life time value of the Clinch River output is expressed in 1981 dollars? That is essentially what I just asked you.

Mr. WILLIS. We will provide it.

Senator HUMPHREY. In fact, I have asked you that as well. So let us talk to Mr. Wallace, if we may.

You are Deputy General Counsel?

Mr. WALLACE. Yes.

Senator HUMPHREY. You have been in legal positions with TVA for the last 26 years and Deputy Counsel since 1975?

Mr. WALLACE. That is correct.

Senator HUMPHREY. Now, you, Mr. Wallace, are one of the four people who signed the BRC study, the breeder reactor corporation study, completed March 15 on the request of the conference between the houses?

Mr. WALLACE. Yes.

Senator HUMPHREY. And what role did you have in this task force on alternative financing for Clinch River?

Mr. WALLACE. Mr. Chairman, my role was largely as a conduit to the other task force members for information to and from TVA technical staff.

The other role was to be sure that the proposals and alternatives examined were consistent with TVA's legal and contractual obligations under the four-party agreement.

The purpose of the task force, of course, was to determine private financing alternatives. This largely involved examination of investment and tax matters that TVA is not involved in and has no particular expertise in. The great bulk of the study was done by the other members, including representatives of Wall Street investment firms. Mr. Gordon Corey, who was chairman of the task force, was former chief financial officer of Commonwealth Edison, and very familiar with private investment matters.

My role was relatively minor.

Senator HUMPHREY. You describe your role as that of a conduit.

Are you saying you were essentially an adviser on energy law; is that correct?

Mr. WALLACE. No, sir. The task force had counsel, Mr. Carl Hobelman, and he did the corporate-type legal work for the task force.

Senator HUMPHREY. You describe your role as minor and yet you are one of the four persons that reports. That suggests that your role was major.

Mr. WALLACE. Of the four I would probably rank myself at the end of the line.

Senator HUMPHREY. Nevertheless, your significant nature indicates that no matter how you rank yourself among the four, you are in the top four and you, therefore, subscribed to the findings of the report, I assume.

Mr. WALLACE. Basically, yes. I am certainly not an expert in investment and tax matters; these matters are beyond my experience or TVA's interest and experience. Overall, I had great respect for and great confidence in the people who did participate in the task force and who were experts in these things.

The task force report was based on a number of technical and economic studies, which I am sure you and your staff are familiar with, done by Oak Ridge National Laboratories, the Stoller Corp., and other who are real experts in the fields they worked in.

Senator HUMPHREY. Your answer was so interesting I have forgotten the question.

Did you file any minority or dissenting views to this report?

Mr. WALLACE. No, sir.

Senator HUMPHREY. So despite your research, you fundamentally endorsed the report?

Mr. WALLACE. Yes. I think the study was well done by people who knew what they were doing.

Senator HUMPHREY. How did you come to be involved in this study group?

Mr. WALLACE. Mr. Willis asked me to participate. The fact that TVA was a major participant in the project under the existing arrangements, I think, necessitated that we at least participate in the group.

Senator HUMPHREY. Mr. Willis, did you volunteer TVA to participate in this study or were you asked by someone?

Mr. WILLIS. BRC asked if we wanted to have a member, and I agreed for the reasons Mr. Wallace indicated. We wanted to be in there because of the impact of our current arrangements. And what impact it may have in the future. So I thought it prudent for us to have someone on the task force.

Senator HUMPHREY. After your initial commission to participate, Mr. Wallace, when you were asked to participate in the study group, were you issued any sort of instructions?

Mr. WALLACE. No sir.

Senator HUMPHREY. There were no preconditions or instructions attached to your participation?

Mr. WALLACE. No, not from anyone.

Senator HUMPHREY. Speaking for TVA—and Mr. Willis is invited to answer if he wishes—are there any ideas or proposals within the report that you disagree with or oppose?

Mr. WILLIS. I have not fully read the study in detail. We do not have any basic disagreement with the thrust of the report as far as

I can tell. It is a sound concept, if you can find a willing buyer, then you look at financing.

Senator HUMPHREY. That is the only thing we lack here, is a willing buyer. A pretty minor shortfall.

Referring to modification No. 1 of the original agreement between the parties, you already stated that you are obligated to take the output, so that answers that question.

In your capacity as assistant counsel, Mr. Willis, in as much as Clinch River project is located within the TVA region and will be operated by—that has been decided. You have not decided whether you will operate Clinch River?

Mr. WILLIS. We have the obligation to operate it during the 5-year demonstration.

Senator HUMPHREY. You have to operate it and take the output?

Mr. WILLIS. Yes.

Senator HUMPHREY. Inasmuch as the Clinch River is located within the TVA region and will be operated by TVA and its output, unless you can find someone else to stick it with, will have to be taken by the TVA, under those conditions, would Clinch River be a TVA plant facility, in your legal opinion, Mr. Wallace.

Mr. WALLACE. When you say would it be a "TVA plant or facility," there might be many different legal contexts that question could arise in. Do you have one in particular in mind?

Senator HUMPHREY. Yes. I am concerned about section 15(d) of the TVA Act which prohibits wheeling of powers, is that a correct interpretation?

Mr. WALLACE. No sir, not quite. Section 15(d) was added by Congress—

Senator HUMPHREY. Prohibited wholesales outside the TVA region?

Mr. WALLACE. Basically, yes sir. Section 15(d) was added by Congress in 1959 in connection with self-financing authorizations. Prior to 1959 the TVA generating capacity that we would build to provide for the needs of our customers was financed by Congress through appropriations. In 1959, Congress authorized us through self-financing, to issue revenue bonds, to provide the money necessary to build plants to meet the loads on our system—that is for the customers that we serve.

At the same time that they gave us this authority to borrow money, they limited the area in which we could sell power. This was frankly to prevent substantial expansion of TVA into private power company areas.

Section 15(d) contains a territorial limitation that was enacted as part of that. In general it provides that TVA not become "a source of power supply", that is the act's wording, outside the region that we served on July 1, 1957.

Senator HUMPHREY. In as much as Clinch River is within the TVA region, it is going to be operated by TVA, you guys have to buy it. Does section 15(d) prohibit you from selling it wholesale outside your region?

Mr. WALLACE. Under section 15(d), if we buy the power from Clinch River and take it onto our system for our use, then its use by TVA would be subject to section 15(d).

Senator HUMPHREY. Proscribed by section 15(d).

Mr. WALLACE. Within the area and the circumstances set forth. But 15(d) does not prohibit us from wheeling power for others. Now wheeling is simply an arrangement, a very common arrangement, between utilities where a utility that generates power on its system arranges with a nearby utility to transmit that power over its transmission lines to a third utility where the power is used. The power supply obligation in that case would be with the utility that is generating the power. The function of the utility doing the wheeling is to provide transmission service—very much like that of just renting part of its transmission system.

Senator HUMPHREY. Yes, I understand.

Mr. WALLACE. Section 15(d) does not limit wheeling arrangements.

Senator HUMPHREY. It does not limit wheeling but does preclude, proscribe?

Mr. WALLACE. If the Clinch River plant were sold to someone else, to either a utility or some other entity—an investment entity—and that entity contracted with some utility to buy the power, then in my opinion we could wheel that power over our system to the purchasing utility without violating section 15(d).

Senator HUMPHREY. The proponents of alternative financing suggest that perhaps Southeast Electric Reliability Council would be interested in buying electricity from Clinch River. Assuming that you operated and have to take the output, would the sale of electricity under those circumstances to Southeast Electric Reliability constitute a wholesale sale in violation of section 15(d) or would that—

Mr. WALLACE. I do not understand that the Southeast Reliability Council buys or sells power.

Senator HUMPHREY. The utilities who make up that organization?

Mr. WALLACE. We can exchange power with any utility with whom TVA had a power exchange arrangement in July 1957. We can and do have many different power arrangements back and forth between them. So to answer your question one would have to know which particular utility would be in the market for the power as well as the detailed aspects of the contractual arrangements. I have been speaking generally about the provisions of section 15(d) of the TVA Act dealing with the area within which TVA may be the "primary source of power supply." We have not had the need to consider applicability of those provisions to a situation where TVA was merely operating a plant owned by others. Of course, these provisions do not limit the disposition of power by entities to which TVA may make power available. Likewise, they would not limit TVA's participation in various possible contractual arrangements which are common business practices among utilities so long as TVA did not become the primary source of power supply. Clearly, however, where TVA has not bought the power and is not marketing it as TVA power, no question would arise under section 15(d).

Senator HUMPHREY. As its power?

Mr. WALLACE. Yes.

Senator HUMPHREY. Let us say that as is the case in your present obligations that you operated it, and you have to take the output. Is that your power?

Mr. WALLACE. That would be our power.

Senator HUMPHREY. If you sell it to utilities within SERC or desire to, can you, under section 15(d)?

Mr. WALLACE. We can sell it to any utility with whom we had power exchange arrangements in July 1957.

Senator HUMPHREY. Is it correct under these exchange arrangements you have, to ultimately buy back virtually as much as you have sold?

Mr. WALLACE. No, sir.

Senator HUMPHREY. Do you have to buy back any?

Mr. WALLACE. Not necessarily. Customarily we do, but as to any particular transaction, that would not necessarily be the case.

Senator HUMPHREY. What is the purpose of the exchange arrangements?

Mr. WALLACE. Various purposes.

Senator HUMPHREY. Peak sharing?

Mr. WALLACE. One is peak shaving, one is what is called economy interchange. If one utility is operating a very high cost source, say an oil fueled plant, and another utility has a very low-cost plant idle, like a low-cost coal plant, then it is quite customary to enter into an arrangement where the high cost utility will cut back its expensive plant and buy that amount of power from the low-cost utility. There are others, also.

This is done back and forth but there is no requirement that any particular kilowatt hour of energy be replaced.

Senator HUMPHREY. Will you provide us, for the record, as soon as possible, a list of the various utilities who are members of SERC and to which ones you could sell electricity from Clinch River without violating section 15(d) and to which one the sale of electricity would constitute a violation?

Mr. WALLACE. Yes.

[The information requested follows:]

MEMBERS OF SOUTHEAST ELECTRIC RELIABILITY COUNCIL
TO WHOM TVA CAN PROVIDE POWER UNDER
POWER EXCHANGE ARRANGEMENTS

The TVA Act recognizes that TVA, when economically feasible, may make exchange power arrangements with other power generating organizations with which it had such arrangements on July 1, 1957. The systems with which TVA can exchange power may, of course, be involved in various types of transactions with other entities, utilizing, if they desire, the power received from TVA.

TVA had express exchange power arrangements involving the following power generating organizations on July 1, 1957.

Appalachian Power Company
Carolina Power & Light Company
Cincinnati Gas & Electric Company
East Kentucky Power Cooperative
Electric Energy, Inc.
Central Illinois Public Service Company
Illinois Power Company
Kentucky Utilities Company
Middle South Utilities, Inc.
Union Electric Company
Kentucky Utilities Company
Louisville Gas & Electric Company
Mississippi Power & Light Company
Southern Company Services, Inc.
Alabama Power Company
Georgia Power Company
Gulf Power Company
Mississippi Power Company

There may have been other such arrangements which are not expressly so identified.

Senator HUMPHREY. Will you give us some characterization of the quantity of electricity you could sell to those you are permitted to sell to?

Mr. WALLACE. It would be many times 350 megawatts. Most of the utilities surrounding us, these include some very large systems, are qualified under section 15(d) as utilities with whom we had exchange arrangements in 1957. It includes much of the Southeast with the exception of Florida.

Senator HUMPHREY. Let us again, assuming that you have to do, as you are bound to do, operate and separate the electricity from Clinch River, what would be the situation if some of that electricity was sold to consumers such as the Department of Energy at Oakridge or Paducah, would the sale of electricity to DOE at Oakridge and/or Paduca define Clinch River as a TVA facility.

Mr. WALLACE. If we have purchased power from Clinch River and then we resell that power to DOE, it would come within the framework of section 15(d). On the other hand, if some other entity, some investment entity, owned Clinch River and it contracted for the sale of power to DOE, then that would not be prohibited, and TVA could wheel the power for the parties.

Senator HUMPHREY. What if some of the Clinch's output were sold to private consumers within the TVA region?

Mr. WALLACE. If we had purchased the power from Clinch River and they are our customers, it is just our power.

Senator HUMPHREY. Does that make Clinch River a TVA facility?

Mr. WALLACE. Well, I do not attach any specific significance to the phrase TVA facility.

Senator HUMPHREY. I do.

Mr. WALLACE. This does not appear in section 15(d), it is not a term within our act. It would not be a TVA facility unless we have a property interest in the facility in the general legal sense.

Senator HUMPHREY. So your opinion—

Mr. WALLACE. But under 15(d) the important issue is the power supply obligation; whose obligation is it to supply that power? If it is TVA's obligation to supply power to a customer or utility, then 15(d) applies; if it is somebody else's obligation to supply the power, then it would not.

Senator HUMPHREY. Is there any legal precedent for the operation by TVA of a non-TVA plant, legal or historical?

Mr. WALLACE. The only plant that we have operated that we did not own is the plant in Memphis, Tenn., the Allen Steam Plant, but that was under lease. We have not, prior to the contracts here, ever operated someone else's plant. Clinch River would be the first time and that is the arrangements that we are now under.

Senator HUMPHREY. Mr. Willis, has any utility formally or otherwise made known to you their desire that you might wheel the output from Clinch River to them?

Mr. WILLIS. Not to my knowledge.

Senator HUMPHREY. Thank you very much.

I stated at the outset that the proponents of alternative financing for Clinch River suggested that there are three possible uses of its output that might facilitate alternative financing. One is that the Department of Energy might buy all or some of the output for its enrichment programs—Secretary Voigt has made it clear he is

not interested in that; TVA has made it clear, witnesses have made it clear that they are not interested in our in need of the output of the TVA for their own system, so that leaves the possibility of wholesaling the output to some other utility or consortium. So let us talk with Mr. Chandler.

Mr. Chandler, you are no longer with GAO, is that correct?

Mr. CHANDLER. I once worked as a consultant to the General Accounting Office; I no longer am a consultant.

Senator HUMPHREY. But you were one of the researchers in the GAO analysis of nuclear plants which was instrumental, I am told, in the decision by TVA to defer some five plants and possible deferral of another eight, is that correct?

Mr. CHANDLER. I will not flatter myself that they took my advice. But I did.

Senator HUMPHREY. I am trying to build you up.

Mr. CHANDLER. I did participate in the study called Electric Energy Options Hold Great Promise for the Tennessee Valley Authority, which is the GAO study published in 1979 that did recommend cancellation of those plants.

Senator HUMPHREY. Have you had a chance to examine the North American Electricity Reliability Council analysis of SERC's electricity demand and supply forecast?

Mr. CHANDLER. I have, yes.

Senator HUMPHREY. What do you think of its projection for need of 16 megawatts of additional capacity by the year 2000?

Mr. CHANDLER. First, I would make a couple of comments about the report itself. It is a report, it is not a demand projection per se, it is not a study or a forecast. What the authors did was to simply compile demand projections by the various electric utilities in all the regions of the country, including the Southeast Reliability Council Region, and to that extent they compiled demand scenarios that were prepared in a variety of different ways ranging from the sophistication with which TVA now prepares its forecast to simple trend interpolations. So there is a question of validity of the methodology to begin with.

One thing that illustrates that the report and the inference that 16,000 megawatts will be required in the Southeast region might not be valid is the example of how the forecast for the TVA was treated in this report. The Reliability Council simply took the TVA high demand forecast and reported that as the level of electric capacity needed in the TVA system in 1990 or 1995, whatever the years are. As I stated earlier, TVA assigns great probability to the fact that they believe that demand will be lower than that scenario to base revenue projections on that report is a very continuous thing to do.

Senator HUMPHREY. What do you consider to be a more reasonable forecast?

Mr. CHANDLER. A more reasonable forecast in my opinion would be one similar to what Al Kaufman has done at Congressional Research Services where he looked at the increases in cost of power and looked at the increases of growth regional product and forecast for that region, for the Southeast region, a 26-percent reserve margin in the year 1995.

I might add that one thing that makes that projection conservative is an assumption on Mr. Kaufman's part that there will be additional delays in the construction of capacity, generating capacity in that region, beyond what was assumed in the North American Electric Reliability Council study. So, in many ways that is a conservative forecast and it does conclude that no additional capacity beyond what is underway will be necessary at the Clinch River would be proposed for sale.

Senator HUMPHREY. DOE, in its analysis of the worth of Clinch River electricity, claims that the figure 14 to 16 cents per kilowatt in 1990 is reasonable for the Southeastern region. Do you agree with that?

Mr. CHANDLER. I do not understand that figure. I have tried to do some simple arithmetic to determine what kind of inflation rate would be necessary to get from the wholesale price of electricity today which is somewhere in the 2½-cent range to 15 cents in 1991 and that assumes that the price of electricity is going to increase at an annual rate of 22 percent. If you assume that inflation is going to be on the order of 7 percent, that is a very high rate of increase.

Senator HUMPHREY. What has been the historical increase in the last 5 years, let us say?

Mr. CHANDLER. TVA's price of residential electricity has doubled since 1970. However, that was a period of rapid change in the TVA system. The overcommitment of new capacity led to those cost increases. They have gotten that somewhat under control and possibly 2 percent per year above inflation is what a lot of people are projecting, not just for TVA, possibly even less than the TVA system. But in the Southeast certainly.

Senator HUMPHREY. Two percent above general inflation?

Mr. CHANDLER. Above inflation.

Senator HUMPHREY. The BRC report suggests that tax breaks or credits might be necessary to secure private investment in alternative financing. Are such arrangements economically efficient or simply appropriating more money in a straightforward tax?

Mr. CHANDLER. Well, I have done a lot of work on stimulating energy conservation investments. So as a result, I have looked at the feasibility of using Federal tax credits for investments in conservation and one of the things I learned, to my disappointment in fact, was that Federal tax credits have what I would characterize as a very little bank for the buck. Nevertheless, the revenue losses to the Treasury will exceed the additional investment that you leverage with those tax credits. Economists such as Dale Jorgenson, Brimmer Sinai and others, for example, estimate that the amount of investment that you actually get per dollar of revenue lost, with the tax credit in general, is about 65 cents. So what that means is that direct Federal appropriations for an investment would be more efficient, would cost the Treasury less money.

Senator HUMPHREY. That is interesting if not revolutionary insight and that would also disappoint a lot of people in this town. Would you make available to us, those studies so we can include them in the record?

Mr. CHANDLER. Surely.

[The information requested follows:]

Environmental Policy Institute

317 Pennsylvania Ave. S.E. Washington, D.C. 20003

202/544-2600

June 9, 1983

Senator Gordon Humphrey
Senate Office Building
Washington, D.C. 20510

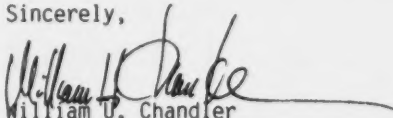
Dear Senator Humphrey:

Enclosed is the information which you requested regarding the effectiveness of the investment tax credit for stimulating new investment. The numbers provided in the enclosed table represent "bang for the buck" estimates. That is, the figures show how many dollars worth of new investment is generated for every dollars worth of revenue lost through use of the tax credit.

Note that the estimates all indicate "bang for the buck" values of less than one dollar for every dollar of revenue lost. This is not surprising, since the tax credit is given not just to the new investments stimulated, but to all qualifying investments. That is, the credit is given to investments already planned as well as to those stimulated by the existence of the credit. This is not to say that the credit is always undesirable, since in some cases the credit provides up-front cash flow which facilitates an investment with very large social, or external, returns. This is generally not the case, however, with energy-related investments.

References for the estimates are provided at the foot of the table. Thank you for your interest.

Sincerely,



William U. Chandler
Director,
Energy Conservation Project

Effectiveness of the Investment Tax Credit:
Investment Stimulated per Dollar of Tax Revenue Lost

<u>Study Reference</u>	<u>\$ of Investment/\$ of Revenue Loss</u>
a.	\$.68
b.	.56

NOTES:

- a. Andrew F. Brimmer and Allen Sinai, "The Effects of Tax Policy on Capital Formation, Corporate Liquidity and the Availability of Investable Funds: A Simulation Study", Journal of Finance, May 1976, pp. 287-308.
- b. Allen Sinai and Otto Eckstein, "Tax Policy and Business Fixed Investment Revisited", Data Resources, Inc., Series No. 83, December 1981, McGraw Hill. The ratio used applies to equipment investment. Ratios for plant investment and business fixed investment are lower, ranging from .18 to .44.

Senator HUMPHREY. I want to offer all the participants an opportunity to add something further at this point, if they would care to and if not, let me thank you very much indeed for your help and your patience and your time here today. May we have these requested answers within 15 calendar days?

The record will remain open for that period and the members of the committee will be inserting various statements in the record.

Thank you. The subcommittee stands adjourned.

[Whereupon, at 12:45, the subcommittee adjourned.]

[Mr. Chandler's prepared statement and additional information follow:]

STATEMENT
OF
WILLIAM U. CHANDLER
DIRECTOR, ENERGY CONSERVATION PROJECT
ENVIRONMENTAL POLICY INSTITUTE AND CENTER

CLINCH RIVER AND THE SOUTHEAST POWER SURPLUS

Introduction and Summary

The Breeder Reactor Corporation and the U.S. Department of Energy propose to finance construction and operation of the Clinch River Breeder Reactor Project in part with sales of electricity and sale of the plant itself. My statement examines the feasibility of this DOE/BRC proposal in the context of surplus electric generating capacity in the Tennessee Valley Authority service area and throughout the southeast region. My statement also examines other basic assumptions made in the BRC and DOE background analyses supporting the alternative financing proposals.

The proposals to fund the CRBRP by selling the power it generates and ultimately the plant itself require forecasting electric power demand. This necessity reminds me of the advice of Alvin M. Weinberg who as my former employer once warned me, "Never make a prediction until you are very old: you might live to see it not come true."

The long lead-time necessary for building power plants, however, requires that we estimate electric power requirements at least a decade in advance. Projections can be made with econometric and engineering energy demand models, and their reliability can be judged by assessing the models'

ABBREVIATIONS

BRC..... Breeder Reactor Corporation
CRBRP..... Clinch River Breeder Reactor Project
DOE..... U.S. Department of Energy
GAO..... U.S. General Accounting Office
NERC..... North American Electric Reliability Council
SERC..... Southeast Electric Reliability Council
TVA..... U.S. Tennessee Valley Authority

assumptions and methodologies. The Tennessee Valley Authority, for example, projects electric power demand in its service area through the year 2000 with one of the most sophisticated sets of models used in the utility industry. Thus, the saleability of CRBRP power in the TVA region can be viewed in the light of TVA's demand projections. Similarly, the saleability of CRBRP electricity can be considered using studies of future power demand in the entire southeast region.

A review of future power demand in the TVA region and for the entire southeast leads to two basic conclusions:

1. There is close to a 90 percent probability that TVA will not need Clinch River power through the end of the century.
2. It is highly improbable that the Southeast region will need Clinch River power through the end of the century.

The likelihood that there will be no market for Clinch River power is so great that it undermines a fundamental requirement set by the DOE/BRC drafters of alternative financing plans: "to establish a stable and predictable financial basis for cost-effective completion of the plant".¹ DOE and BRC concluded that CRBRP power would be saleable largely on the basis of a survey of future power demand that is inappropriate for power demand planning.

Furthermore, basic assumptions made by BRC/DOE in their background analyses, including the future price of electricity in the southeast, are at best inconsistent with published DOE estimates and at worst invalid.

TVA Obligations Regarding CRBRP Power

The Tennessee Valley Authority is obligated by contract to purchase CRBRP power, if any is generated, for the first five years of its operation. TVA would pay the BRC for this power at a rate equal to TVA's

avoided generating costs. This rate, presumably, would equal the cost of fuel and operation and maintenance expenses for power generation facilities replaced, and would neither cost nor save TVA customers any money. TVA ratepayers should and would not bear any of the initial capital cost of the CRBRP. The CRBRP would be a demonstration plant and by definition would be an unreliable source of power, at least though the initial five-year demonstration phase. TVA, in any case, will have excess generating capacity through this period (1991-1995), and could not justify the purchase of additional generating facilities. Thus, it would be unfair to charge TVA consumers for any unproven facility even if additional capacity were needed.

The Department of Energy, however, proposes that the CRBRP be sold to raise funds after five years of plant operation. The price of the plant would be determined by estimating the present value of future revenue streams from sales of electric power. TVA is obligated to determine this value and would have first right of refusal. The question then becomes, "Will TVA need to buy capacity equal to the CRBRP in 1996, and, if not, can the power be sold in the surrounding region?"

TVA Power Demand in 1995

"Will TVA need new generating capacity in 1995?" If the probable answer is "No", then BRC faces a much less stable and predictable financial future.

The probability of TVA needing any new capacity, according to TVA's demand forecasts, is very small. Table 1 reproduces TVA's most recent

TABLE 1
Tennessee Valley Authority
Generating Capacity vs. Projected Peak Demand
(Megawatts)

Year	Firm Capacity	Projected Demand		
		High	Medium	Low
		(Includes 20 % reserve margin)		
1983	32,000 MW	24,800	24,800	24,800
1990	37,000 MW	30,500	27,900	25,100
1995	37,000 MW	34,700	30,400	25,600
2000	37,000 MW ^a	39,300	33,000	26,600

NOTE a: This figure assumes that TVA does not complete deferred capacity totalling 5324 megawatts. See Table 2.

SOURCE: Derived from "Load Forecast Summary Prepared for Fiscal Year 1983", Tennessee Valley Authority, p. 5, and the TVA Information Office.

demand forecast,² including High, Medium, and Low peak electric demand scenarios. TVA estimates that there is a 90 percent probability that³ actual demand in 1995 will be lower than forecast by the high scenario. TVA's forecast means that it is highly unlikely that peak power demand in the TVA system will exceed 34,700 megawatts (peak demand plus a 20 per cent reserve margin) in the year that sale of Clinch River would be negotiated.

TVA currently owns approximately 32,000 megawatts of installed electric generating capacity. By 1988, TVA will have completed an additional 5000 megawatts now under construction for a total of 37,000 megawatts of power generation capacity. But peak electric demand will be far lower. TVA, in fact, estimates that there is only a 10 per cent chance that demand will exceed 34,700 megawatts in 1995. Thus, TVA will probably have 2300 megawatts of excess capacity in 1995, the year in which the Breeder Reactor Corporation and the Department of Energy propose to sell the CRBRP. There is very little chance that TVA would want to buy the breeder.⁴

Under a more probable TVA demand projection (the "Medium" scenario) TVA will have an excess of 6600 megawatts in 1995, and 4000 megawatts in the year 2000.⁵ Even in the highest demand scenario, the Authority would need no new capacity until 1998.

Even if TVA did require new capacity, TVA would be obligated to complete deferred facilities. TVA has deferred completion of 5324 megawatts, plants on which TVA has already spent approximately \$2.5 billion.⁶ TVA has recently cancelled approximately 5150 megawatts at a loss of \$1.85 billion, an amount which TVA ratepayers will be paying for many years.⁷ To incur such a loss, TVA must feel confident that it will not need additional capacity. (See Table 2.)

TABLE 2

TVA Deferred and Cancelled Generating Capacity

<u>Category</u>	<u>Megawatts</u>	<u>Cost</u>
Capacity Cancelled	5150	\$1.8 billion (loss)
Capacity Deferred	5324	\$2.5 billion (to date)

SOURCE: TVA Nuclear Cancellation Background Paper; TVA Information Office; U.S. General Accounting Office, "TVA Is Justified In Deferring The Yellow Creek Unit 1 Nuclear Powerplant"; and "Tennessee Valley Authority Budget Program for the Fiscal Year Ending September 30, 1983", February 1982, p. 111.

TVA demand forecasts, since the late 1970's, have been expertly prepared. One major uncertainty makes them less reliable, however. The level of power demand for federal uranium enrichment could reduce the⁸ aforementioned TVA capacity requirements by 1925 megawatts. According to TVA:

Long-term electricity requirements for DOE uranium enrichment on the TVA system are characterized by extreme uncertainty.⁽⁹⁾

TVA attributes this uncertainty to decreased enrichment requirements and the likelihood that the Department of Energy would curtail power purchases from TVA before its other, less expensive suppliers (namely, Electric Energy, Inc., and Ohio Valley Electric Cooperative), and earlier adoption¹⁰ of Advanced Isotopic Separation technology.

In this context, it would at best be risky for the BRC to plan to sell the CRBRP to TVA.

Demand for Power in the Southeast

The saleability of CRBR power elsewhere in the southeast region will depend on four factors: regional growth in the demand for power; completion of planned generating facilities; the cost of new sources of power; and the ability of any new CRBR consortium to wheel power out of the TVA service area.

The Department of Energy study of alternative financial mechanisms for the CRBR implies that new capacity totaling 16,000 megawatts will be required in the Southeast Electric Reliability Council (SERC) region by 1995:

The area is projected to require 16,000 MWe of additional capacity to serve peak demand periods by 1995. The CRBRP output would displace only about 2 percent of the projected new demand in 1995.(11)

This projection appears to have been based on a report prepared by the North American Electric Reliability Councils,¹² a report which is inadequate in several respects. First, the report is not a study, per se. The authors did not study and project southeast region electric demand, they simply compiled estimates of demand made by the electric utilities, and the quality of the forecasts made by the utilities varies greatly. Utility forecasts may be sophisticated projections such as those made by TVA, or they may be mere trend extrapolations. Any compilation of utility scenarios, therefore, will be of dubious value.

The unreliability of the NERC study is illustrated by its treatment of TVA demand. NERC projects 1991 power demand in the TVA system by using only the TVA "High" demand scenario. TVA, you recall, described this scenario as having a 90 percent probability of being too high.

A recent study by the Congressional Research Service¹³ projects that the southeast region (SERC) will have a reserve electric capacity margin of 35 percent in 1990, and 26 percent in 1995. The latter amounts to 6 percent more capacity than is commonly considered "adequate", and 11 percent more than is considered "acceptable". The projection, moreover, is based on a moderately high rate of economic growth (3 percent annual), and a moderating rate of increase in electric prices (2 percent annual). See Table 3. CRS also assumes greater delays in construction of new facilities than does NERC; that is, if NERC's estimates of new construction are correct, the reserve margin would be even larger than CRS projects.

TABLE 3
Projected Peak Power Demand and Capability
In the Southeast Region
1990 and 1995

<u>Year</u>	<u>Peak</u> (Megawatts)	<u>Capacity</u> (Megawatts)	<u>Reserve Margin</u> (Percent)
1990	111,000	149,000	35
1995	133,000	167,000	26

SOURCE: Alvin Kaufman and Karen K. Nelson, "Do We Really Need All Those Electric Plants?", U.S. Congressional Research Service, Report No. 82-147 S, August 1982, p. 49.

The prospect of low power demand growth in the southeast makes the sale of the CRBRP unlikely. This, in turn, makes a central element of DOE's alternative financing scheme untenable.

Constraints On Wheeling CRBRP Power

Even if power demand growth made the CRBRP saleable, legal constraints on wheeling power will at a minimum add great uncertainty to any financial proposal involving sale of CRBRP power. Sections 211 and 212 of the Federal Power Act have made wheeling of power almost impossible except where all involved utilities agree to cooperate. If, for example, power had to be wheeled from the TVA system to a utility customer by first utilizing the transmission system of an intermediate utility, the willing consent of the intermediate utility would be essential.¹⁴

If TVA buys CRBRP and attempts to wheel its power to another system, further difficulties would arise. The TVA Act (Section 15d) prohibits sale of TVA electricity to any utility not already receiving power from TVA in 1959. Some 12 utilities are permitted to receive TVA electricity, however, and could buy and in turn sell TVA electricity to another utility. The cost and complexity of this type of arrangement, however, has precluded such sales in the recent past.¹⁵

Competitiveness of CRBRP Power

The saleability of Clinch River power would be reduced by the unreliability and high cost inherent in any demonstration plant. The Department of Energy suggests, however, that CRBRP power could be competitive:

To build a single coal-fired 350 MWe plant (comparable to the CRBRP output) utilities are projected to spend \$584 million (1984 dollars) for a plant going on line in 1991.

An analysis of the cost of baseload electricity using coal as fuel was performed for the period during which CRBRP will operate. Analyses covered a range of cost projections between 14.6¢ and 15.7¢ per KWH in 1991 in year of expenditure dollars.(16)

These estimates may be misleading. The lower kWh cost cited above is 50 percent higher than DOE published cost estimates for coal-fired power coming on-line in the southeast in the 1990's.¹⁷ The capital cost cited is approximately forty percent higher than published DOE estimates, reflecting, perhaps, an unrealistic assumption that a utility would build a small (350 megawatt) coal-fired plant rather than capture the economies of scale of a larger (600 megawatt) facility.

Conclusion

Revenue projections made by the Department of Energy and the Breeder Reactor Corporation on the basis of sale of electricity and/or the CRBRP after the initial five year demonstration phase of the plant are extremely tenuous. Revenue estimates have been based on levels of electric capacity demand in the southeast that are improbable, and on electric price levels that are inconsistent with published DOE estimates. The DOE/BRC analyses, therefore, fail to meet their own basic criterion, to establish a stable and predictable financial basis for cost-effective completion of Clinch River. A shortfall in CRBRP revenues would be likely if the plant were built, and these would have to be made up by federal appropriations.

REFERENCES

1. U.S. Department of Energy, assistant Secretary for Nuclear Energy, Office of Breeder Reactor Programs, "Report To The Congress On Alternative Financing Of The Clinch River Breeder Reactor Plant Project", March 1983, Washington, D.C., p. iii.
2. Tennessee Valley Authority Office of Power, "Load Forecast Summary Prepared for Fiscal Year 1983", Chattanooga, Tennessee, September 1982.
3. The TVA forecast referenced actually gives demand in megawatts for the years 1990 and 2000. The forecast also provides estimated growth rates for interim years. These rates are used in the following common compound growth formula to derive the 1995 estimates:

$$a_1 = a_0 e^{rt}$$

where

a_1 = megawatt total in forecast year

a_0 = megawatt total in base year

$e = 2.7182818$

r = rate of growth as forecast by TVA

t = time, in years, between base year and forecast year.

4. Capacity additions were derived from "TVA Is Justified In Deferring The Yellow Creek Unit 1 Nuclear Powerplant", U.S. General Accounting Office, GAO/EMD-82-114, July 30, 1982, p. 24.
5. TVA "Load Forecast Summary Prepared For Fiscal Year 1983, op cit, p. 51.
6. Tennessee Valley Authority, "Nuclear Cancellation Background Paper", unpublished TVA paper on file at the Environmental Policy Institute, dated July 13, 1982, p. 3.
7. See Reference 3.
8. TVA "Load Forecast Summary Prepared for Fiscal Year 1983", p. 28.
9. IBID, p. 26.

10. IBID, p. 28.
11. See Reference 1, p. 10.
12. North American Electric Reliability Council, "Electric Power Supply and Demand, 1982-1991", August 1982.
13. Alvin Kaufman and Karen K. Nelson, "Do We Really Need All Those Electric Plants?", Congressional Research Service, Report No. 82-147 S, August 1982.
14. For a discussion of this situation, see "FERC As A Least-Cost Electric Regulator", Hearing before the Subcommittee On Energy Conservation and Power, Committee On Energy and Commerce, U.S. House of Representatives, Second Session, April 23, 1982, Serial No. 97-152, pps. 139-143.
15. U.S. General Accounting Office, Letter to The Honorable Robert Walker and John Heinz, "Analysis of the Feasibility of Tennessee Valley Authority Power Being Made Available through Power Exchange Arrangements to General Public Utilities (GAO/EMD-82-129), September 30, 1982.
16. U.S. Department of Energy, op cit, p. 10.
17. U.S. Department of Energy, "Projected Costs of Electricity from Nuclear and Coal-Fired Power Plants", Volume 1, Table S1, p. xi, August 1982. The DOE projection is presented in 1980 dollars for a coal fired power plant with scrubbers coming on-line in the Southeast region in 1995. The figure cited in this testimony is compared with the DOE "Alternative Financing..." report figure by inflating the former to 1991 dollars (the same as the latter) at a 7 percent annual rate (the rate suggested in the former DOE report).

TENNESSEE VALLEY AUTHORITY ACT

[48 Stat. 58 (May 18, 1933), as amended by 49 Stat. 1075 (August 31, 1935), 53 Stat. 1083 (July 26, 1939), 54 Stat. 611 (June 26, 1940), 55 Stat. 599 (July 18, 1941), 55 Stat. 775 (November 21, 1941), 66 Stat. 330 (July 3, 1952), 66 Stat. 591 (July 12, 1952), 68 Stat. 968 (August 30, 1954), 73 Stat. 280 (August 6, 1959), 73 Stat. 338 (August 14, 1959), 80 Stat. 346 (August 12, 1966), 82 Stat. 885 (September 28, 1968), 84 Stat. 915 (October 14, 1970), 86 Stat. 206 (June 6, 1972), 88 Stat. 390 (July 25, 1974), 89 Stat. 750 (November 28, 1975), 90 Stat. 376, 377, 380 (April 21, 1976), 90 Stat. 1258 (September 14, 1976), P.L. 96-97 (October 31, 1979); 16 U.S.C. secs. 831i831c, 831d-831h-1, 831i-831dd]

AN ACT

To improve the navigability and to provide for the flood control of the Tennessee River; to provide for reforestation and the proper use of marginal lands in the Tennessee Valley; to provide for the agricultural and industrial development of said valley; to provide for the national defense by the creation of a corporation for the operation of Government properties at and near Muscle Shoals in the State of Alabama, and for other purposes

Sec. 15d. (a) The Corporation is authorized to issue and sell bonds, notes and other evidences of indebtedness (hereinafter collectively referred to as "bonds") in an amount not exceeding \$30,000,000,000 outstanding at any one time to assist in financing its power program and to refund such bonds. The Corporation may, in performing functions authorized by this Act, use the proceeds of such bonds for the construction, acquisition, enlargement, improvement, or replacement of any plant or other facility used or to be used for the generation or transmission of electric power (including the portion of any multiple-purpose structure used or to be used for power generation); as may be required in connection with the lease, lease-purchase, or any contract for the power output of any such plant or other facility; and for other purposes incidental thereto. Unless otherwise specifically authorized by Act of Congress the Corporation shall make no contracts for the sale or delivery of power which would have the effect of making the Corporation or its distributors, directly or indirectly, a source of power supply outside the area for which the Corporation or its distributors were the primary source of power supply on July 1, 1957, and such additional area extending not more than five miles around the periphery of such area as may be necessary to care for the growth of the Corporation and its distributors within said area: *Provided, however,* That such additional area shall not in any event increase by more than 2-1/2 per centum (or two thousand square miles, whichever is the lesser) the area for which the Corporation and its distributors were the primary source of power supply on July 1, 1957; *And provided further,* That no part of such additional area may be in a State not now served by the Corporation or its distributors or in a municipality receiving electric service from another source on or after July 1, 1957, and no more than five hundred square miles of such additional area may be in any one State now served by the Corporation or its distributors.

Nothing in this subsection shall prevent the Corporation or its distributors from supplying electric power to any customer within any area in which the Corporation or its distributors had generally established electric service on July 1, 1957, and to which electric service was not being supplied from any other source on the effective date of this Act.

Nothing in this subsection shall prevent the Corporation, when economically feasible, from making exchange power arrangements with other power-generating organizations with which the Corporation had such arrangements on July 1, 1957, nor prevent the Corporation from continuing to supply power to Dyersburg, Tennessee, and Covington, Tennessee, or from entering into contracts to supply or from supplying power to the cities of Paducah, Kentucky; Princeton, Kentucky; Glasgow, Kentucky; Fulton, Kentucky; Monticello, Kentucky; Hickman, Kentucky; Chickamauga, Georgia; Ringgold, Georgia; Oak Ridge, Tennessee; and South Fulton, Tennessee; or agencies thereof; or from entering into contracts to supply or from supplying power for the Naval Auxiliary Air Station in Lauderdale and Kemper Counties, Mississippi, through the facilities of the East Mississippi Electric Power Association: *Provided further,* That nothing herein contained shall prevent the transmission of TVA power to the Atomic Energy Commission or the Department of Defense or any agency thereof, on certification by the President of the United States that an emergency defense need for such power exists. Nothing in this Act shall affect the present rights of the parties in any existing lawsuits involving efforts of towns in the same general area where TVA power is supplied to obtain TVA power.

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TENNESSEE VALLEY AUTHORITY ACT

[48 Stat. 58 (May 18, 1933), as amended by 49 Stat. 1075 (August 31, 1935), 53 Stat. 1083 (July 26, 1939), 54 Stat. 611 (June 26, 1940), 55 Stat. 599 (July 18, 1941), 55 Stat. 775 (November 21, 1941), 66 Stat. 330 (July 3, 1952), 66 Stat. 591 (July 12, 1952), 68 Stat. 968 (August 30, 1954), 73 Stat. 280 (August 6, 1959), 73 Stat. 338 (August 14, 1959), 80 Stat. 346 (August 12, 1966), 82 Stat. 885 (September 28, 1968), 84 Stat. 915 (October 14, 1970), 86 Stat. 206 (June 6, 1972), 88 Stat. 390 (July 25, 1974), 89 Stat. 750 (November 28, 1975), 90 Stat. 376, 377, 380 (April 21, 1976), 90 Stat. 1258 (September 14, 1976), P.L. 96-97 (October 31, 1979); 16 U.S.C. secs. 831-831c, 831d-831h-1, 831i-831dd]

AN ACT

To improve the navigability and to provide for the flood control of the Tennessee River; to provide for reforestation and the proper use of marginal lands in the Tennessee Valley; to provide for the agricultural and industrial development of said valley; to provide for the national defense by the creation of a corporation for the operation of Government properties at and near Muscle Shoals in the State of Alabama, and for other purposes

Sec. 12. In order to place the board upon a fair basis for making such contracts and for receiving bids for the sale of such power, it is hereby expressly authorized, either from appropriations made by Congress or from funds secured from the sale of such power, or from funds secured by the sale of bonds hereafter provided for, to construct, lease, purchase, or authorize the construction of transmission lines within transmission distance from the place where generated, and to interconnect with other systems. The board is also authorized to lease to any person, persons, or corporation the use of any transmission line owned by the Government and operated by the board, but no such lease shall be made that in any way interferes with the use of such transmission line by the board: *Provided*, That if any State, county, municipality, or other public or cooperative organization of citizens or farmers, not organized or doing business for profit but primarily for the purpose of supplying electricity to its own citizens or members, or any two or more of such municipalities or organizations, shall construct or agree to construct and maintain a properly designed and built transmission line to the Government reservation upon which is located a Government generating plant, or to a main transmission line owned by the Government or leased by the board and under the control of the board, the board is hereby authorized and directed to contract with such State, county, municipality, or other organization, or two or more of them, for the sale of electricity for a term not exceeding thirty years; and in any such case the board shall give to such State, county, municipality, or other organization ample time to fully comply with any local law now in existence or hereafter enacted providing for the necessary legal authority for such State, county, municipality, or other organization to contract with the board for such power. *Provided further*, That all contracts entered into between the Corporation and any municipality or other political subdivision or cooperative organization shall provide that the electric power shall be sold and distributed to the ultimate consumer without discrimination as between consumers of the same class, and such contract shall be voidable at the election of the board if a discriminatory rate, rebate, or other special concession is made or given to any consumer or user by the municipality or other political subdivision or cooperative organization: *And provided further*, That as to any surplus power not so sold as above provided to States, counties, municipalities, or other said organizations, before the board shall sell the same to any person or corporation engaged in the distribution and resale of electricity for profit, it shall require said person or corporation to agree that any resale of such electric power by said person or corporation shall be made to the ultimate consumer of such electric power at prices that shall not exceed a schedule fixed by the board from time to time as reasonable, just, and fair; and in case of any such sale, if an amount is charged the ultimate consumer which is in excess of the price so deemed to be just, reasonable, and fair by the board, the contract for such sale between the board and such distributor of electricity shall be voidable at the election of the board: *And provided further*, That the board is hereby authorized to enter into contracts with other power systems for the mutual exchange of unused excess power upon suitable terms, for the conservation of stored water, and as an emergency or breakdown relief. [48 Stat. 65-66, 16 U. S. C. sec. 831k.]

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BREEDER REACTOR CORPORATION

P.O. BOX 767, CHICAGO, ILLINOIS 60690

March 12, 1983

Mr. Wallace B. Behnke
Chairman
Project Management Corporation
Post Office Box 767
Chicago, IL 60690

Hon. Donald Paul Hodel
The Secretary of Energy
Department of Energy
Forrestal Building
1000 Independence Avenue, SW
Washington, DC 20585

Gentlemen:

As you know, Breeder Reactor Corporation, as part of its responsibility to provide senior counsel to the Clinch River Breeder Reactor Project ("CRBRP"), has assembled a task force to explore possible alternative financing possibilities for supplementing future Federal appropriations supporting the construction and operation of the Project.

Within the few weeks available, the task force considered future financing options based on possible values of the plant, its revenues, the values of possible tax credits, and other values. A report on the results of the consideration of these issues by the task force to date is enclosed for your information and use.

In forwarding the task force report along with a number of my personal observations, I would like to point out the preliminary nature of the studies undertaken by the task force and the absence of that type of detailed review at this stage that would normally be attendant to such transmittals. Because of a desire to provide information in a useful form in a brief period of time, the task force has had limited opportunity to exchange comments and ideas with others. The task force report has not yet been reviewed by the BRC Board of Directors or the organizations they represent, but is being transmitted to the Board herewith.

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The task force recognizes that there are many risks and uncertainties involved in determining the market value of a first-of-a-kind demonstration project such as the CRBRP at this stage of its development. They relate to licensing, plant completion, testing and operation, the potential market for the plant's electricity, competition for funds and other government resources and other issues. The task force is well aware that additional guidance from the utility industry, the nuclear equipment industry, the financial community, and government will be required to permit the exploration in more detail of the potential impact of such considerations on possible financing options.

There are a number of ways in which financial assistance could be provided. However, experience with each of these options on other projects suggests that further meaningful development of the most promising options for this Project depends on the government's role and its commitment for the long term to the CRBRP and to the nuclear power policies and programs tightly interwoven with this Project.

The BRC Board of Directors has frequently reaffirmed its position that the CRBRP is a unique project of great national value, warranting continued industry support and DOE's highest priority for available Federal funding and other support. Among its responsibilities to this Project, DOE has an obligation under current Project arrangements to continue to seek sufficient Federal funding to see the Project through to completion. As the task force report points out, access to private financial markets for supplemental funds will require a complex of government commitments and assurances.

Much of the criticism and debate concerning the CRBRP is now structured around the financial consequences of the delays which have plagued the Project. These delays are largely the result of changing and conflicting Federal policies and plans and organizational and financial decisions, along with the extraordinary inflationary pressures which affected the economy for several years. These are matters over which the utility and industrial participants in the Project have had no control.

The Project's managers and the industrial base have performed remarkably well in areas within their control, despite extended delays in licensing and construction, the Project's first-of-a-kind development characteristics, and the impact of the Three Mile Island accident on new licensing requirements by the NRC. Project design is almost 90% complete.

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Major components, both completed or on order, total \$740 million, representing about 75% of the major nuclear components. Site preparation work is well underway. More than \$1.5 billion has already been invested in the Project.

I understand that more than 3,500 government and contractor employees throughout the United States are currently working on the Project, including highly skilled scientists and engineers, factory workers, and construction trades personnel, and that the Project includes a significant commitment to minority contracting and minority employment. Moreover, because of its advanced stage of design, proceeding to full-scale construction will permit the employment of several thousand additional personnel.

The task remaining is to complete the design and construct and operate the plant to demonstrate the practical characteristics of breeder technology.

BRC is convinced that demonstration of the Liquid Metal Fast Breeder Reactor (LMFBR) technology is essential to its continued development. The CRBRP has evolved from costly, but productive, engineering investments by both government and industry since the 1950's. The national LMFBR research and development program has confirmed the technical and engineering feasibility of the LMFBR concept and the CRBRP. A well-documented technological base has been reinforced by a well structured, experienced industrial base building on the government's scientific and laboratory resources and the guidance of the nation's utilities. Operation of the Experimental Breeder Reactor II, the successful start-up and full-power operation of the Fast Flux Test Facility (FFTF), increasing confidence in nuclear fuel performance and knowledge of key technology-related safety and licensing matters have contributed to increased engineering confidence and have helped reduce the R&D and first-of-a-kind risks in the CRBRP design. Nevertheless, uncertainties remain.

Further progress in the LMFBR program requires, first, maintenance of industry confidence that the CRBRP can be completed and successfully operated. Primary attention can then be directed to arrangements for the design and construction of a utility-sized demonstration plant. Information gathered from the FFTF and the CRBRP will not only be essential to the design of a larger plant, but will also

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enhance the ability of the U.S. to enter into meaningful international collaboration for further development of the LMFBR.

The overall LMFBR program, and the role and responsibilities of government and industry within that program, are patterned after the successful experience with Shippingport, Dresden, Yankee and other major nuclear projects in the AEC's Power Reactor Demonstration Program. DOE publications show estimated government expenditures for Light Water Reactor (LWR) plant research and development and fuel cycle support at about \$5 billion. I understand that at this stage the private sector has invested well over \$150 billion and committed billions more to carry this LWR technology from the demonstration plant phase into the commercial introduction and deployment phases. Over the past ten years, consumers have saved about \$25 billion because the LWR option has been available to the nation's electric utilities.

The nation is on the right track in building up and integrating a technological, engineering, industrial, and construction force infrastructure and demonstrating its practicality in careful steps before proceeding to commercial introduction of the LMFBR concept. In addition to the \$1.5 billion already invested in the CRBR Project, countless other investments in dollars, time, facilities, and technology in the industry and in the base R&D program would be placed in jeopardy or lost, if a decision were made to further delay or cancel the CRBRP at this stage. If a decision were made to continue to carry out a strong breeder program without the CRBRP, the cost to the nation would certainly be much greater than presently required. No better nor more economically realistic alternative has been proposed and supported in a meaningful manner.

For more than thirty years, every President, every Congress, and the industrial and scientific community have supported the premise that this nation must have viable domestic energy options to support our economy, our security, and our ability to maintain effective domestic and foreign policies. Events within the past ten years, here and abroad, provide ample justification to move forward with a sense of urgency to achieve these objectives. Studies of viable domestic alternatives have confirmed that nuclear power must continue to play a major role in achieving these national goals. One of the most critical elements of the nuclear option is the government's long-standing commitment to the expeditious

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development and demonstration of the LMFBR to permit the private sector to make market decisions regarding its future commercial development.

The following points, which have emerged from a review of assessments of our domestic energy options by government, industrial, and scientific bodies, impress me as vital in the context of our nation's nuclear power program:

At this stage, a decision not to sustain a strong national breeder program would imply the phasing out of nuclear fission as a domestic energy source.

If the future role of nuclear power is viewed as uncertain, but a nuclear option is to be maintained, constructing and operating a breeder demonstration plant is necessary.

Such a demonstration plant is an integral and key element of the breeder research and development program; no commitment to build commercial breeder plants could possibly be considered or made unless and until the construction and operation of such a demonstration plant have been evaluated.

The CRBRP is the only technically acceptable, economical, and timely demonstration plant available.

America must retain and develop all of its few promising long-term energy sources, including breeder reactors. Events during the past decade of turbulence in energy supplies have confirmed the wisdom of the decisions which led to planning for the CRBRP and have reinforced the need for its aggressive completion. The Project warrants the highest priority for continued support by government and industry.

National security, industrial strength, and economic well-being all require adequate and reliable supplies of electrical power at reasonable rates. Long-term projections for economic recovery dictate that the nation must have demonstrated electric energy supply options to support long-term growth. At present, only coal and nuclear fuel can be relied upon to fulfill these bulk power needs in the foreseeable future.

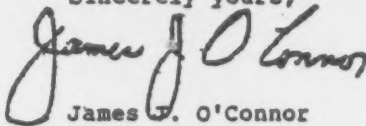
Congress has committed a substantial sum, over \$18 billion, and authorized the formation of special government-

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industry institutional arrangements in an important effort to stimulate the development and demonstration of domestic synthetic fuels technologies by the private sector. While a smaller financial commitment will be required for the breeder, a comparable national commitment to further development and demonstration of the LMFBR technology is essential.

I hope that the task force submittal along with my comments will help encourage constructive attention to the completion of the CRBPP and to the serious national energy R&D issues which are focused on the Project.

Sincerely yours,



James J. O'Connor
Chairman

cc: BRC Board of Directors

EXPLORATION OF ALTERNATIVE
FINANCING POSSIBILITIES FOR
THE CLINCH RIVER BREEDER
REACTOR PROJECT

A task force report to the Breeder
Reactor Corporation on alternative
financing possibilities for the CRBR
Project.

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HIGHLIGHTS OF THE BRC
TASK FORCE REPORT

- o The CRBR Project can attract significant new-source capital funds, perhaps as much as forty percent of the \$2.4 billion remaining cost to complete.
- o Some of this can be provided by capitalizing on the value of the Project through firm contracts for its power output, supported by appropriate Federal assurances.
- o The amount of private investment will be enhanced by assuring the availability of conventional Project-related tax incentives.
- o Sufficient and timely funding must be provided to maintain optimum construction schedules; vigorous efforts must be continued to prevent slippages and unnecessary cost increases. This will require prompt action by Congress, DOE and the private sector.
- o Further schedule delays cannot be tolerated because of their effect on costs.
- o Legislation will be needed to assure timely Federal support and to amend the existing Project authorization so as to permit requisite Federal assurances with respect to completion, licensing and operability of the Project.
- o One way to facilitate private financing would be to create a new entity, possibly a joint-venture, with a Federal corporation or agency as general partner and private investors as limited partners. The financing framework would be similar to that used for any large construction partnership in that tax benefits could be allocated among the partners.
- o No single approach or set of alternatives is recommended. The Task Force stands ready to assist in determining how best to proceed.

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March 12, 1983

REPORT OF THE CLINCH RIVER
BREEDER REACTOR PROJECT
TASK FORCE

Overview

This report describes a number of possibilities for minimizing Federal budget requirements for the Clinch River Breeder Reactor (CRBR) Project and securing greater participation from private investors. It concludes that significant new-source funding can be secured for the Project if Federal efforts are clearly centered on the twin goals of completing the Project promptly and providing the kinds of firm assurances and tax benefits which private investors generally require for a project of this magnitude.

General Background

On December 3, 1982, at a meeting of the Breeder Reactor Corporation (BRC) Board of Directors, James J. O'Connor, Chairman of the Board, authorized the assembly of a Task Force to make an objective examination of alternative financing possibilities for the CRBR Project. The Task Force includes representatives of the electric utility industry and investment banking community with legal and technical advisors. Its formation, which is based upon BRC's responsibility to provide "senior counsel to [Project Management Corporation] PMC in the interests of the Project" (BRC/PMC Agreement, Article XIV(c)), was in response to Congressional concern about the level of future Federal budget appropriations for the Project as expressed in a Senate Appropriations Committee report. Later in December, Congressional Conferees approving fiscal year 1983 funding for the Project required the U.S. Department of Energy "... to vigorously explore proposals including a reconsideration of the original cost-sharing arrangement, that would reduce Federal budget requirements for the Clinch River Project or project alternative, and secure greater participation from the private sector." (H.R. Rep. No. 97-980 at 186, 97th Cong., 2d Sess., 12/20/82.) The DOE was directed to submit its findings to the cognizant Congressional committees not later than March 15, 1983.

In view of the action of the Conferees, the Task Force is submitting the following report, exploring possible Project financing proposals, to BRC.

The membership of the BRC Task Force was established in January, 1983. Its first meeting was held late that month. In carrying out its task, the Task Force consulted with outside financial and banking experts, some corporations involved in the Project, and the DOE. The limited time available prior to March 15 has necessitated a broad definition of alternative proposals rather than detailed specification of precise institutional vehicles, statutory changes and contractual terms that must ultimately be developed when the DOE, the private sector and the cognizant Congressional committees determine the preferable course to follow in order to assure, to the extent possible, the continued progress of the CRBR Project towards final design, construction and operation.

Several guiding principles underlie the Task Force's approach to the issues presented by alternative financing proposals. These include the following:

- o The CRBR is essentially a national research and development effort and an important part of the National Liquid Metal Fast Breeder Reactor (LMFBR) program.
- o The CRBR Project can result in an electric generating facility with significant marketable value and output. However, there are far too many uncertainties relating to its licensing, construction, completion, and operation to be financed independent of Federal financial aid and legislative and administrative support.
- o The CRBR Project, if successful, will not be available for the sale of power until 1990. Projections of costs and revenues at that point and for up to 30 years thereafter are necessarily speculative and uncertain. Thus, the estimates presented in this report (based on information provided by DOE) should serve only as a general guide for the purpose of estimating future financing requirements.
- o The existing Project arrangements were worked out with great care and have established rights and obligations which should not be disregarded in assessing alternative proposals. Such proposals should complement the present contract arrangements to the extent possible.
- o The Task Force has not offered political assessments of alternative proposals, but has

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assumed favorable legislative action to support reasonable financial alternatives designed to "reduce Federal budget requirements."

Risks, implications and uncertainties involved in determining the ultimate degree of reliability of this first-of-a-kind developmental project and the market value of its output have not been dealt with exhaustively. These uncertainties include those relating to licensing, back-fitting, completion, testing and operation; the R & D role of the Project; the potential market for its electrical output; and the need to compete for Federal funds and other Government resources. A great deal of additional guidance from the electric utility industry, the nuclear equipment industry, the financial community and the Federal Government will be required to estimate the future commercial value of the Project with the degree of certainty needed to determine precisely how much capital can be raised from private investors.

The detailed findings of the Task Force are set forth in the following sections.

I. Cost to Complete

Under the May 4, 1976 Project Agreement, the DOE is obligated to use its best efforts to obtain from Congress whatever additional funds are needed to complete the Project and demonstrate the technology.

The Task Force was asked by BRC to explore alternative sources of Project financing and to advise BRC whether such alternative sources, when coupled with continuing Federal appropriations at roughly present levels, will be adequate to complete the Project. The Task Force did not make an in-depth examination of the Project schedule and costs, but was provided with DOE's latest construction schedule and cost estimates which indicate that the CRBR Project can be completed by October 1989 at an estimated remaining expenditure of \$2.4 billion after FY 1983. These estimates assume that the construction schedule is not constrained by further funding limitations. Thus, the completion date and remaining expenditures are highly dependent upon resolution of existing funding uncertainties. If the construction schedule were to slip, the estimated remaining cost to complete the Project could increase significantly.

For purposes of this report, the Task Force accepted DOE's estimate of \$2.4 billion to complete the Project, assuming that further delays will be avoided; and recognizing that this assumption (and, hence, the cost estimate itself)

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depends upon prompt actions relating to the resolution of Project funding.

The deleterious effect of delays. It is enormously costly to delay or stretch out any large construction project, particularly a large R & D project, such as the CRBR Project, due to additional carrying charges during the delay period, escalation of construction costs, and added expenditures associated with using less than optimal construction forces. Members of the Task Force have had direct experience with such delays and, accordingly, all of the projections in this report assume prompt Federal action, including timely future funding by the Congress, so as to permit optimal work scheduling from this point on. Absent these, the conclusions of this report cannot be supported.

II. New-Source Funding Needs

Future contributions from the electric utility industry, already committed, will provide \$172 million, and other contributors will provide \$5 million, for total future contributions of \$177 million. While part of these contributions are scheduled to be made after FY 1991, it is assumed that all such amounts can be made available for funding Project construction plus interim financing costs, to the extent they must be paid currently.

Assuming minimum future Federal funding at roughly current levels for a total of \$1.4 billion subsequent to FY 1983, the additional amount required to be provided from new sources, in order to fund total Project costs, would be about \$800 million, as shown in the following table:

TABLE I
REMAINING CAPITAL REQUIREMENTS

	<u>Billions</u>
Federal funding	<u>\$1.4</u>
Utility contributions and others	<u>0.2</u>
New-source funding required	<u>0.8</u> <u>u</u>
Total funds needed	<u>\$2.4</u>

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Adding a modest allowance of \$300 million for those out-of-pocket financing costs which must be paid during the construction period, an estimate of \$1.1 billion seems reasonable for the Project's future new-source funding needs, but this amount can vary widely, depending upon the financing plan selected.

III. New-Source Funding Requirements Exceed the Probable Proceeds of a Sale of the Project Itself

The maximum future market value of the CRBR Project, measured in terms of the likely avoided cost of constructing alternative coal-fired units equipped with scrubbers, is not expected to exceed \$2,300 per KWe.*

If the 330 MWe conservative net rating of CRBR were priced at \$2,300 per KWe, the result would be \$750 million. If the 380 MWe design net rating were priced at \$2,300/KWe the result would be nearly \$900 million. However, the facility is worth less than that today because achievement of a commercial level of reliable operation is at least nine years away. Moreover, steps must be taken to reduce completion risks and the like before Bankable** securities can be sold and full market value realized.

IV. Power Sales Constraints

Studies show a probable need for additional electric generating capacity in the SERC region in the early to

* Generation in the Southeastern Electric Reliability Council (SERC) Region, outside of Florida, is predominantly coal-fired. The \$2,300 figure is derived from a range of estimates available from several sources for base-load coal-fired capacity installed in the SERC region for commercial service in 1992 (the earliest date at which commercially reliable output is expected to be available) -- in short, ten years hence -- and using annual cost escalation rates in the 8% to 9% range.

** The terms, "Bankable" and "Bankable Commitments", as used herein, mean that the contract or obligation in question is sufficiently firm to provide adequate security for a non-recourse loan, advance, leasehold investment, or equity participation.

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mid-1990s. However, utilities in that region may be reluctant to assume certain risks associated with long lead-time commitments for CRBR power, namely:

- o projected load growth in the SERC region may not materialize;
- o the level of power revenues needed to pay Project debt service and other financing costs may exceed the purchasers' "Avoided Costs;"* and
- o the Project may not be able to produce the power contracted for.

Regulated electric utilities tend to be inhibited from making risky long-term capacity commitments because the regulatory penalties for over-commitment are severe. In view of the possibility that such penalties might be imposed, regulated utilities in the SERC region may be reluctant to enter into long-term obligations today (i) to purchase minimum annual quantities of CRBR power, or to purchase the Clinch River Project itself (or the Balance of Plant, i.e., the Project excluding the Nuclear Steam Supply System) because anticipated load growth might not materialize; or (ii) to pay a specific minimum price for CRBR power because that price might prove to be in excess of their systems' Avoided Costs.

Nevertheless, the Task Force is confident that, if appropriate arrangements are developed, such reluctance can be overcome. However, the very existence of such reluctance is evidence of the need for the kinds of assurances deemed essential, as discussed below.

* "Avoided Costs" is a technical term derived from Section 210 of the Public Utility Regulatory Policies Act (PURPA). Section 292.101(b)(6) of the regulations implementing that Act defines "Avoided Costs" as follows:

"(6) 'Avoided Costs' means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the . . . qualifying facilities, such utility would generate itself or purchase from another source."

The PURPA regulations generally provide that electric utilities must pay full avoided costs for electricity generated by small power producers and cogenerators.

V. Range of Possible Market Values

The CRBR Project will have significant potential market value when completed and the plant is operating as a base-load electrical power plant. Realization of that value prior to the end of the shakedown period (now scheduled for mid-1992) will depend upon unconditional Federal assurances, as discussed below. Such realization may be accomplished in a variety of ways, as follows:

- o sale of the Project,
- o sale of the Balance of Plant (BOP), accompanied by a viable steam supply contract, and
- o pledge of the future revenue stream.

Sale of the Project. As a practical matter, it would be difficult to sell the entire Project today (or to sell securities approaching its full value) because the accident at Three Mile Island and the controversy surrounding the Washington Public Power Supply System (WPPSS) nuclear program, have left investors leery of large nuclear power plant projects, whether or not they are backed by apparently firm governmental assurances. This suggests that the inherent value of the plant itself would have to be supplemented by a long-term power sales agreement backed by an unconditional Federal warranty of minimum revenues.

Setting aside, for the moment, the value of the revenue warranty, it is reasonable to assume that the Project itself may ultimately be worth as much as the coal-fired capacity which would otherwise have to be built. Applying the \$2,300 per KWe figure already mentioned to the full 380 MWe net rating of the Project indicates that the maximum capacity value of the Project may, in 1992, approach \$900 million. The tax benefits normally associated with plant construction and ownership would provide additional value which, however, cannot be quantified at this time.*

Sale of the BOP. The BOP would have little market value without an assured supply of steam. A contract to supply such steam at an assured price per Kwh would be essential if the BOP were to be sold for a significant amount. A long-term power sales agreement backed by Federal assurances would also

* There should be no net loss to the Government through the use by CRBR of existing construction-related tax benefits. This is because any such benefits used in connection with the CRBR will displace those that would otherwise have applied to new capacity displaced by CRBR.

be required. The amount for which the BOP could then be sold would depend, of course, upon the terms of those two contracts. Assuming that the steam contract were designed to maximize the value of the BOP, then the BOP might be sold for a significant figure, not because of its replacement value in terms of turbine generator, condenser, switchgear and the like, but because of the value of the future net revenue stream (after deducting steam supply costs), coupled with construction-related tax benefits already referred to.

A simple pledge of the warranted future revenue stream. The value of the future power output of the Project will vary depending upon the amount of assured output and the net revenue per Kwh available to cover debt service and equity return. For example, minimum net revenues of 6¢ per Kwh (after deducting fuel, other operation and maintenance expenses) on an assured annual output of two billion Kwh for 20 years beginning in 1992 would provide \$120 million a year, an amount adequate to pay the debt service (and equity return), at an assumed 10% annual cost of money,* on approximately \$1 billion invested in 1992 -- \$1,020 million. A minimum net price of 6¢ per Kwh does not seem unreasonable for the 1990s and thereafter, in terms of Avoided Cost projections for SERC region utilities which have committed their 1990s capacity needs. However, bus-bar electricity cost projections from new coal-fired units in the SERC region for the 1990s and thereafter are in the 15¢ per Kwh or higher range. If net revenues pegged at this level or modestly lower could be assured through firm DOE contracts, significantly larger amounts could be provided.

It should be emphasized that to be Bankable, the power contracts must be the hell-or-high-water type. In short, they must guarantee the payment of annual dollar amounts adequate to cover financing costs no matter what happens.**

-
- * The precise interest rate applicable to the financings referred to above and hereinafter would depend upon market conditions when such financings were arranged. In today's market, a 10% annual rate is on the optimistic side. However, other assumptions set forth herein tend to be on the conservative side.
 - ** With moderate economic growth over the long-term, new capacity is expected to be required in the SERC region. Thus, while firm utility contracts to purchase power at displaced capacity rates will be difficult to achieve in the near term, as future capacity needs become clear such contracts may be forthcoming. Thus, while Federal revenue assurances will be needed in the near term, the Government might not have to pay on such assurances unless, of course, the expected economic growth and capacity requirements do not materialize when needed.

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In setting forth the foregoing range of 1992 values, the Task Force avoided pinpointing a precise value because it will depend upon the character of the arrangements provided. However, several relevant observations can be made:

- (1) It appears that the market value in 1992 (for investment purposes) may be in the range of \$1 billion.
- (2) If the Project or the BOP is purchased by investors, the investment value can possibly be enhanced through conventional construction-related tax benefits, viz, those associated with amounts invested in newly-constructed depreciable property.
- (3) The amount of funds which can be made available to cover actual construction expenditures will vary widely depending upon when the money is actually invested. For example --
 - o The ¹⁹²proceeds of a \$1 billion investment in 1993, if invested in 1983 with no interest or other return payable for ten years, would provide useable funds (in 1983) of only \$385 million, assuming 10% annual cost of money.
 - o If the funds are invested in 1988, the net amount thus available (again assuming no interest or other return payments until 1993) would be \$620 million.
 - o Alternatively, if the funds are invested in four equal annual amounts, from 1986 to 1989 inclusive, such investments would amount to \$150 million a year for a total of \$600 million.

Given the range of possible investment values arising from varying revenue streams, tax considerations and present value discounting, a carefully worked-out plan will be required to thread one's way through the array of opportunities and obstacles confronting the Project financing. The Task Force stands ready to assist in developing acceptable arrangements for capitalizing on the future market value of the CRBR Project in order to obtain significant financial support for the Project.

VI. Suggested Plans to Capitalize on the Value of the Project

The future market value of the CRBR Project can be capitalized on, if, and only if, the licensing, completion and operating risks are eliminated through prompt Federal action. Also, appropriate fuel supply assurances must be provided and private investors assured that future revenues will be adequate to earn an appropriate return on, and return of, their investment.

As indicated in the foregoing Sections, several approaches seem feasible:

- (1) Straight-forward borrowing based upon future power supply contracts.
 - o The DOE might contract to purchase the entire CRBR output for use in its uranium enrichment plants, with annual payments sufficient (net of operating costs) in any event to pay the debt service. That contract could then be pledged as security for a long-term loan.
 - o Alternatively, the DOE might warrant that the CRBR will produce a minimum amount of power and provide price supports such as those proposed for synthetic oil in the mid-1970s when the Government offered to provide such oil at a support price for resale to user utilities. There is ample precedent for price support in Public Law 96-294, the Energy Security Act. Such price supports should be adequate to cover all debt service requirements.
- (2) Sale of Partnership equity interests and debt securities of an entity which would purchase and own the entire CRBR Project.
 - o To be marketable, such Partnership equity interests would require broad Federal assurances as to the deliverability of a reliable and acceptable facility.
 - o Long-term power sales contracts (like those described under (1)) would also be required.

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- o In order to realize the full extent of available tax benefits, favorable IRS rulings would be essential.

(3) Sale of Partnership equity interests and debt securities of an entity which would purchase and own only the BOP.

- o This approach would require all those items discussed under item (2) except that BOP operating risks might be assumed by the owners.
- o In addition, an acceptable steam supply contract would be required because, without such a contract, commercial viability cannot be assured.
- o With appropriate contractual provisions, this approach may be the best way to maximize the tax benefits associated with the Project.

Conclusion. Under any of the foregoing plans, it would be feasible to work out arrangements so that payments received for the future value of the Project or the BOP would be adequate to provide significant investment support.

VII. Other Approaches to Funding Capital Requirements

The only other way to obtain significant additional capital funds from private investors would be to provide other assets or potential benefits adequate to assure that the investor will get something of value in return and be compensated for risk.

Potential "assets" not already discussed fall into six categories:

- (1) Assurances that private investors will recover their investment and the cost thereof if timely Federal appropriations are not provided, and that annual appropriations will be continued if the Project is delayed.
 - o Such a commitment would assure investors that the Federal Government intends to see the Project through to completion despite past uncertainties.

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- o It would also facilitate interim financing during periods of peak construction expenditures.
- (2) Additional tax incentives, similar to those associated with any large capital-intensive R & D project.
- o Such tax incentives would not be a wind-fall for investors; instead, they would be designed to provide additional "value" which the Project can offer in exchange for funds invested. For full discussion, see the appendix prepared for the Task Force by tax counsel.
- (3) Other source of funds.
- o Possibilities include additional warranties by manufacturer/vendors and architect/engineers and additional R&D commitments from manufacturer/vendors and architect/engineers, or the domestic electric utility industry. Local regulation and the controversial nature of the CRBR Project would make it very difficult to raise such funds from either the regulated electric utility industry or the Electric Power Research Institute. Any attempt to do so might well jeopardize existing CRBR funding arrangements.
- (4) Additional foreign R & D commitments.
- (5) Licensing revenues, based upon potential patent rights.
- o Action would be needed to protect breeder R & D from reaching the public domain and make potential worldwide licensing revenues available to support CRBR Project financing.*

Care would have to be taken to assure that such action did not diminish the patent rights of the BRC members under their Utility Contribution Agreements, which could jeopardize collections from such members.

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(6) Direct Federal assurances.

- o If other financial mechanisms are inadequate, the alternative may be for the Federal Government to act as a "deep pocket" guarantor of Project debt, lease obligations and equity returns.

The foregoing Sections outline an array of financing alternatives which are available to the CRBR Project. While the Task Force prefers no single financing approach, the following Sections describe in broad terms one possible financing program which seems promising.

VIII. Possible Financing Entity

- o The CRBR Project is faced with the need for significant funds; and without specific legislation, it would be unable to obtain such funds.
- o Such legislation may be needed to provide necessary warranties and tax incentives. It is also needed to create a financing entity which can use those warranties and incentives.
- o That entity can take several forms but, in any event, it should be designed to bring the Federal Government and a group of private investors together in a single enterprise so as to enable completion (through combined Federal/private financing) of an important R & D facility on which more than \$1.5 billion has already been spent and which it would be foolhardy to junk.
- o Accordingly, the following format is suggested as a basis for further study and review:
 - (a) Its name: whatever it is finally named, it is hereinafter referred to as the "Partnership."
 - (b) The form: A public/private joint venture, created by Federal statute, encompassing both Government and private investment capital.

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- (c) Partners would include a newly created Federal corporation (or the DOE) as general partner and a group of private investors as limited partners.
- (d) The limited partners might be individuals, corporations, or partnerships, depending on tax and regulatory considerations.
- (e) The Partnership would be entitled to receive and allocate tax benefits among its partners.
- (f) Ownership of the Project should be vested in the Partnership. Care should be taken not to disturb present licensing arrangements, but the Partnership should be provided with enough of the characteristics of ownership so that tax deductions and credits can be allocated among the limited partners.
- (g) TVA would operate the Project and wheel power produced pursuant to a keep-whole reimbursement contract.
- (h) At the conclusion of operations and recovery by private investors of their investment, title would revert to the Federal Government. Provision should also be made for decommissioning and waste disposal responsibility to remain in the Federal Government.

IX. Powers of the Partnership

The Partnership should have the following powers, among others:

- o To issue its own debt obligations with Federal warranties, which could include borrowings from the Federal Financing Bank (FFB),* and/or without Federal warranties.
- o To issue limited Partnership equity interests and to allocate tax benefits among the limited partners;

* Alternatively, the Partnership could have the right to sell notes to the U.S. Treasury and Treasury would be obligated to purchase such notes.

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- o To pledge the proceeds from its contracts and agreements as security for its debt, lease, joint venture or Partnership obligations;
- o To ratify and assume obligations under existing contracts and to enter into new purchase, construction and operating agreements, to buy and sell power, to sell and lease back facilities and fuel, etc.;
- o To obtain and hold title to patents and to license the use of such patents worldwide;
- o To enter into appropriate joint ventures related to the CRBR Project;
- o To be exempt from the Public Utility Holding Company Act and the Federal Power Act and not to be considered a regulated public utility for any purpose, state or Federal.

X. Priority Assessment of Actions Needed

In addition to the legislative action needed to create the Partnership with the powers set forth in Section IX, it must be given enough financial substance to allow it to function. Actions required to provide that financial substance have already been described. They are listed below, with only moderate additional amplification, because the listing is intended primarily to indicate their relative priority.

- (1) Assurances must be provided as to completion, licensability and operability.
 - o Such assurances must be unconditional if the required funds are to be obtained, especially in view of the uncertainties surrounding the outstanding WPPSS obligations.
 - o In the event the Project is not completed, licensed and placed in operation, private investors would be entitled to recover the capital they had provided plus a return thereon.
- (2) Assurances must be provided as to the amount of power the Project will produce.

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- (3) Power purchase contracts must be provided for the Project's full output at an assured price.
- o Such contracts may represent either direct Federal power purchases or third-party purchases backed by Federal assurances.
 - o As mentioned earlier, such assurances with regard to power purchases and the price thereof have statutory precedent in the Energy Security Act where, as here, the need for future secure energy justifies such support.
- (4) Provide a Bankable Commitment that adequate Federal funds (at least \$1.4 billion) will be appropriated after FY 1983, or, if not, that private investors would be entitled to recover the capital they had provided plus a return thereon.
- o The commitment should apply to the period from FY 1984 through FY 1990.
 - o It should provide for additional appropriations thereafter until the Project is licensed and achieves a commercial level of reliable operation.
 - o It should be sufficiently firm to be Bankable.
 - o Although the Congress does not normally appropriate funds for more than a year at a time, it should empower the DOE (i) to enter into the sort of commitment described above and (ii) to borrow from the FFB or from the U.S. Treasury the funds necessary to meet such commitments.
- (5) Assure that project-related tax incentives can be allocated among the limited partners, as is customary for all large construction partnerships.
- o These tax incentives, which are generally available to the owners of any large construction project, include investment

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tax credits, accelerated depreciation and the immediate deductibility of certain overhead and operating expenses.

- o It is customary to allocate such project-related incentives among the partners.
- o Consequently, the allocation of these incentives among the Project partners would in no way provide a wind-fall for investors.
- o All expenditures in excess of the Project's market value might be treated as R & D expenditures deductible by the limited partners. This was the formula used in 1955 to aid in financing Dresden Unit Number One (the first privately financed U.S. nuclear power reactor), whereby all expenditures by the Nuclear Power Group (a financing consortium) in excess of the commercial value of the plant were allowed as immediate tax deductions.
- o In case the foregoing conventional tax incentives prove inadequate to provide the capital required, a number of new approaches might be considered. For example:
 - o A special energy tax credit might be provided, applicable solely to the Project.
 - o The Partnership might be empowered to enter into arrangements with the City of Oak Ridge to issue tax-exempt industrial development bonds backed by the Partnership and without regard to the so-called two-county rule.

For further discussion of the matter of tax incentives, see the appendix.

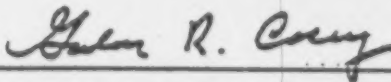
CONCLUSION

The Task Force concludes that the Clinch River Project can support significant private investment, and that the present Government/private business relationship can be enhanced, to the benefit of the entire nation.

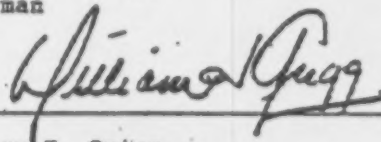
From the viewpoint of the Federal Government, the benefit of obtaining private CRBR financing would be a near-term reduction in Federal budget requirements and increased private participation in the Project. Clearly, Federal assurances, warranties, and tax incentives will be needed in order to attract private financing. However, many of the proposed assurances are contingent and would not be called upon unless the Project failed to perform as expected, or the Government failed to complete the Project on schedule or the power revenues were substantially less than projected. Moreover, the Task Force assumes that the financing arrangements will reserve to the Federal Government the residual value of Project assets.

The Task Force stands ready to assist in determining how best to proceed.

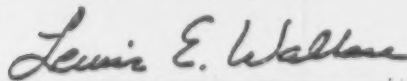
Respectfully submitted,



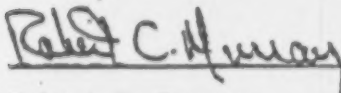
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March 12, 1983

Tax Incentives

Taxes and tax incentives are significant elements in capital costs. The cost of financing is increased to the extent that the investor must pay tax on his investment return, while combinations of tax incentives can both lessen the burden of taxes on the investor's return and, in addition, provide a positive cash flow (thus producing, through the tax system, a stimulus to desired expenditures).

Predictably, such combinations of incentives are popular with the tax-paying public and unpopular with the Treasury Department. They tend also to be popular with Congress because they enable it to encourage research and modernization expenditures without directly appropriating federal funds.

Existing tax incentives for investment come primarily in three forms:

(1) Deductions: the right to deduct costs against income.

This is, of course, not a special incentive unless and to the extent that (i) the costs deducted exceed the costs actually incurred, (ii) the costs are deductible in advance of the period in which they are economically incurred, in which case there is an acceleration of tax reduction, which is equivalent to an interest-free loan for the period of acceleration, or (iii) the costs are, in effect, attributable not to the stream of income against which they are de-

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ducted, but to another stream of income which is exempt from tax.

R & D deductions. Of special importance to this project would be an R & D deduction equivalent to that portion of total project expenditures represented by the estimated excess of such expenditures over the commercial value of the completed facilities as measured by the cost of conventional facilities of the same character.

(2) Tax credits, such as the investment tax credit and the energy tax credit, which reduce the taxpayer's final tax liability. The investment tax credit, for example, will reduce tax liability \$10 for each \$100 of qualified investment, and the energy tax credit, if applicable, will reduce tax liability by an additional amount ranging from \$10 to \$15 under existing law (depending on the type of energy property involved). Prior to this year, those credits did not reduce the amount of taxpayer cost which could be depreciated. Thus, if a taxpayer paid \$100 for an asset eligible for \$20 of ITC and energy credit, the credits were immediately available and the taxpayer's real cost was effectively \$80. Nonetheless, the taxpayer was permitted to depreciate the entire \$100. Thus, the value of the two credits consisted of two elements: (i) \$20 plus (ii) the right to depreciate \$20 which was not in reality an economic cost. The value of that second element depended upon the period over which the depreciation was allowable, but for assets of medium life, a

\$20 credit could produce a reduction of more than that in the cost of capital. The 1982 Tax Act modified this result by providing a reduction in the depreciation base equal to 50% of the amount of the credit (with some optional treatments not here important). In sum, to the extent that credits do not produce a basis adjustment, the value of the credit is larger than the credit percentage indicates.

(3) Exemption of investment income. The income produced by a particular investment may be categorically exempted from tax. In order to understand the interaction of this exemption incentive with other incentives, it is important to think of an investment as economists do (and not as accountants and lawyers do), i.e., as an expenditure which produces a stream of gross income which is then divided among two classes of claimants, creditors and equity owners.

The device widely used to exempt a portion of the income stream is the Industrial Development Bond (IDB), which exempts from tax that portion of the income from the investment which flows to creditors holding such bonds.

Optimum Combination of Incentives

An optimum combination of incentives would maximize in a single transaction all of the above three elements. If, for example, 90%

of a project could be financed with IDB's and the deductions and credits attributable to the entire cost of the project could be preserved for use by the equity owners, the total available tax benefits would be substantial and might produce tax deductions and credits to the equity owner in excess of his tax burdens. If the aim were to minimize total financing costs, it would be important (in that event) to reduce the amount of debt and increase the amount of equity to a point where the tax benefits produced exactly the desired level of cash flow, thus providing the minimum required equity return.

The Treasury Department is understandably critical of such tax planning and has for some years been chipping away at the rules in order to prevent it. As a result, today's applicable rules are a complex network of provisions, limitations, exceptions, cross-exceptions, etc., which can be satisfactorily described only in the context of specific proposals.

For present purposes, it may be sufficient to observe that broad general concepts are in place which could permit an optimum combination, and that one-shot modifications in existing limitations and exceptions would be achievable through legislation if there were a Congressional desire to make the overall project work.

Such legislative amendments would not need to be included in the Internal Revenue Code; but they would almost certainly require approval by the Congressional tax-writing committees, as disting-

ished from the committees having jurisdiction over energy, appropriations, etc.

Equity Ownership

Tax incentives which come in the form of deductions and credits can be fully utilized only by entities which have sufficient taxable income from other sources to absorb those deductions and credits. The level of incentives provided by present depreciation and ITC rules alone is sufficient that, even in an average situation, the taxable income flowing to the equity owners of a new project may not be sufficient fully to absorb the available deductions and credits. The problem is exacerbated if additional credits (such as the energy credit) are available or if there is a significant degree of financing available from other sources.

Thus, if the deduction and credit incentives are to be fully utilized, it becomes necessary to have some legal mechanism to permit them to be flowed through to others (normally equity owners) who can utilize such benefits. (Deductions and credits do not, of course, flow through to ordinary stockholders, so that an equity financing in the form of a conventional public issuance of stock will not achieve the desired result.) Two "flow-through" structures are typically used: (i) a partnership which owns and operates the project, or (ii) a partnership which leases the project to an opera-

tor. There is ample precedent for widely syndicated participation in owner-operator partnerships and, to a lesser degree (because of limitations on ITC in the hands of individual lessors), in lease partnerships. Where wide distribution is desired, it is normally necessary to limit the potential liabilities of individual investors by using a "limited partnership".

In the case of both operating and lease partnerships, if partnership debt is nonrecourse, the so-called "at risk" provisions in existing tax rules generally prevent the full flow-through of depreciation and (subject to certain exceptions) credits where the partners are individuals or closely held corporations. Thus, unless a special exception were made, it would be desirable to confine the equity participation to widely held corporate investors. Even then, if such investors were limited partners, the flow through would not work under existing rules unless the indebtedness were nonrecourse. That makes it absolutely essential that either the indebtedness be backed by an assured and ample cash flow or some legislative exception to the "at risk" rules be obtained.*

A further problem is that individual or corporate partners in a project which constitutes a regulated public utility may themselves be (or fear they may be) subject to public utility rules.

* One possibility would be a mechanism to allow tax benefits associated with this single project, on a one-shot basis, to be transferable to any investor providing significant new capital therefor.

Thus, if the partnership were structured as an operating entity, it may be practical to sell equity participation only to other public utilities. In order to avoid such difficulties, the equity investors might assume the status of owner-lessors, who in turn were to lease to some operating entity. This would normally avoid the regulated public utility problems, but would entail either compliance with or modification of another complicated set of tax rules relating to lessors, all of which are to some extent in flux at this time, but which could almost certainly be temporarily held in abeyance through special legislation.

Debt Financing

Present rules permit the issuance of IDB's for electrical generation only in the case of the "local furnishing" of electricity. This has been interpreted to mean distribution solely within a territory no larger than two counties. The "two-county" rule is a peculiar rule with a peculiar history. Some modifications of it might be possible, on a one-shot basis, but any general relaxation of the rule would open the way for massive tax-exempt financing of electrical generation, which is a frightening spectre to both Congress and the Administration. Unless such fears can somehow be put to rest, the use of IDB's will be difficult to achieve.

Exempt financing would, of course, be available if equity ownership of the facility were in a state or local government entity

But in that case, the positive cash flow benefits of deductions and the investment credit would be unavailable.

It is possible for Congress to authorize the issuance of tax-exempt debt by a new, specially defined not-for-profit corporation which would fit this case. While such an authorization would be plowing new ground, it should not be rejected out of hand.

Miscellaneous Observations

The present energy tax credit has limited applicability and is, in any event, scheduled to expire. Some kind of legislative action would, therefore, clearly be required in order to make that credit or something comparable to it available to the project in question.

If some way could be found to issue tax-exempt debt, the general rules applicable to tax-exempt financing would permit a limited amount of investment of the proceeds in taxable securities pending construction and to some extent after construction. This potential is governed by the so-called "arbitrage rules", which are also complex. These, too, could be relaxed for a special case if Congress desired to do so.

Conclusion

Under optimum circumstances, the tax benefits potentially

available could provide significant additional funds for this project. Such benefits could be provided without having to create basic new concepts or provisions, but coming close to the optimum combination described would almost surely involve some legislative enactments which would require very careful structuring.

No tax windfall. It is important to note that all of the tax incentive structures described have the effect of reducing the cost of the capital investment and do not have the effect of providing anything other than normal returns to private investors. The net result is that the private investors will have a cash flow that returns their investment, together with a reasonable market rate return---no more, no less. The source of their cash---the fact that it comes in the form of tax benefits---is of no consequence to them; they are interested only in dollars. It is immaterial to them who transmits the dollars. Thus, any contribution in the form of tax incentives will flow, in economic effect, not to the investors, but to the project, itself, with any excess being ultimately returned to the federal government through the operation of federal/private financing arrangements already in place.

REPORT TO THE CONGRESS ON ALTERNATIVE FINANCING OF THE CLINCH RIVER BREEDER REACTOR PLANT PROJECT

MARCH 1983



U.S. DEPARTMENT OF ENERGY
ASSISTANT SECRETARY FOR NUCLEAR ENERGY
OFFICE OF BREEDER REACTOR PROGRAMS
WASHINGTON, D.C. 20545

APPENDIX D

CRBRP Revenue Projections

Previous projections of the revenues derived from CRBRP electricity production have been based on the current contract with TVA to purchase CRBRP electricity at TVA's avoided cost.* The TVA/CRBRP contract identifies the last 100 MWE of TVA generated electricity as the basis for estimating TVA's avoided cost. TVA's forecast of this cost implies that electricity from existing coal plants will be displaced during the project demonstration period of FY 1991-FY 1995.

Electricity may logically be sold at an avoided energy cost that recovers only marginal operating costs with no amortization of capital if the power is being supplied on a nonfirm, interruptible basis. For the purposes of this study, however, it is clear that private investors would intend to sell power on a firm basis, operating the plant as a baseload station as it has been designed.

A survey of 25 utilities in the southeastern United States indicated that as of FY 1993 and thereafter, new baseload capacity would be required by a majority of the utilities surveyed in order to maintain a reserve capacity of 20 percent.⁽¹⁾ In addition, analysis of data provided by the Southeastern Electric Reliability Council (SERC) and the Oak Ridge National Laboratory (ORNL) confirms the need for new baseload capacity in the southeastern United States before FY 1995.

The SERC includes Tennessee, the Carolinas, Alabama, Georgia, Florida and portions of Virginia, Kentucky and Mississippi. Except for Florida, all SERC utilities are within an efficient transmission distance of CRBRP. Today, SERC has much more power than it needs to serve electric demand reliably. Also, SERC anticipates enough new capacity to serve projected demand through 1995.⁽²⁾ However, SERC's plans for 1990 (as of 12/31/81) include three coal units which are not yet under construction and three nuclear units whose construction is less than one-tenth complete. There are seven coal units that are planned for Florida which have not been accounted for since Florida is outside the assumed transmission range of CRBRP. If these plants are included,

*In the Public Utility Regulatory Policies Act of 1978, avoided cost is defined as "the incremental costs to an electric utility of electric energy or capacity or both, which, but for the purchase from the qualifying facility or qualifying facilities would generate itself or purchase from another source."

SERC's plans include ten coal units not yet under construction and three nuclear units whose construction is less than one-tenth complete. One of these nuclear plants (North Anna 3) has been subsequently cancelled.

Therefore, SERC's planned capacity of 153,320 MWe in 1990 is, in actuality, only 149,113 MWe of committed capacity beyond 1990.⁽³⁾ Unless SERC actually constructs the planned but not committed capacity, SERC's projected peak demand in 1995 would only be served by a 5 percent reserve margin. In order to serve SERC's projected 1995 peak demand of 141,841 MWe with a 20 percent reserve margin, approximately 16,000 MWe of additional capacity (excluding Florida) will be required. CRBRP power (provided on a firm contract commitment) would only displace 2 percent of these projected 1995 capacity requirements.

It is well recognized that electricity demand forecasts have been revised downward over the last several years. It is also recognized that econometric models are not capable of predicting the underlying structural changes in the use of electricity. These changes, such as improved end-use efficiency, are largely responsible for the need to reevaluate electricity demand forecasts. In order to evaluate the impact of these factors on the required incremental baseload capacity in the CRBRP market area, the Oak Ridge National Laboratory has provided an assessment of power needs in this service area⁽⁴⁾. Two models were employed by ORNL. One model was econometric, while the other model was an integrated end use model. The latter model is explicitly sensitive to the structural changes which have resulted in lower electric power demand forecasts.

The models provided forecasts for a geographic area roughly equivalent to the SERC market area. Four sets of input assumptions were used. These input assumptions correspond to low, medium, and high world oil price cases and to a Southern Regional Growth Case. See reference 4 for details. The range of forecasted peak electricity demand for the SERC market area in 1995 was 143,000-153,000 MWe from the structural end use model and 194,000-203,000 MWe from the econometric model (see Table D-1). The lowest forecast (143,000 MWe) is slightly higher than the recent SERC forecast discussed above (141,841 MWe (see reference (2))). Therefore, our independent analysis of the need for power indicates that at least 17,000 MWe of additional capacity will be required to serve SERC in 1995 with a 20 percent reserve capacity (excluding Florida). If the highest forecast from the structural end use model were used, 27,000 MWe of capacity would be required by 1995. The econometric model forecasts imply much higher required capacities.

The survey of utilities indicated that new coal-fired baseload units are the appropriate alternatives displaced by firm power

supply contracts. Several studies indicated that the most economical increment of this type of capacity is represented by twin 600 MWe coal-fired plants (5, 6). If the revenue requirements of such a plant were used to negotiate CRBRP contracts, utilities would have the advantage and opportunity of purchasing smaller increments of baseload capacity (30 to 330 MWe) at the same cost per MWe as provided by a 1,200 MWe plant. This provides a substantial benefit to utilities since they may avoid construction of less economic units, underutilization of larger units, joint development of larger plants with other utilities, or periods of inadequate reserve capacity. This economic advantage is particularly beneficial to smaller utilities, e.g., municipal utilities.

The revenue requirements of a two-unit coal station (each unit = 600 MWe) were developed for the region by ORNL (6). The capital cost for this plant (scheduled for commercial operation in 1991) is estimated at \$1,250/MWe (1984 \$). If this plant investment is prorated to a smaller 330 MWe plant (equivalent to CRBRP), the plant investment at 1991 commercial operation would be \$412.5 million (1984 \$). This capital cost estimate was used to develop the revenue requirements of a baseload plant displaced by CRBRP. A single coal-fired 350 MWe plant would require a \$584 million investment. Two avoided cost estimates were developed using different coal price projections derived from the 1981 Annual Report to Congress by the U.S. DOE.⁽⁸⁾ The low coal price forecast assumes no real rate of inflation in the price of coal while the high coal price forecast assumes a 2 percent annual real rate of inflation. The low coal price forecast results in a revenue requirement of \$97/MWhr (1984 \$) in FY 1991 while the high coal price forecast increased the revenue requirement to \$104/MWhr. These data are displayed in Tables D-2 and D-3 as Case 1 (low coal cost) and Case 2 (high coal cost). CRBRP is estimated to achieve a capacity factor of 75 percent after the initial shakedown period (see Appendix C). However, in order to provide a conservative estimate of future revenues, a 65 percent capacity factor was used instead.

DOE F 1325-B
(7-79)

U.S. DEPARTMENT OF ENERGY

memorandum

DATE April 14, 1983

REPLY TO
ATTN OF Carmen Difiglio, Office of Policy, Planning, and Analysis (PE-23)

SUBJECT Documentation of Project Revenue Projections for CRRBP

TO Record

I. INTRODUCTION.

The Clinch River Breeder Reactor Plant (CRRBP) Project is a national research and development project. After completion, CRRBP will also be a base load power station with a net capacity of 330 MWe. The Department of Energy recently submitted a report to Congress which discusses the sale of CRRBP's economic value to investors as a way of reducing the Federal expenditures required to realize the R&D benefits of CRRBP.(1)

In order to evaluate CRRBP's economic value, it was necessary to forecast the price for which CRRBP electricity could be sold. Since CRRBP is not being built by a utility to serve its own baseload power requirements, it is necessary to estimate the price at which CRRBP electricity can be sold to utilities in need of power over the life span of CRRBP (1991-2000). In general, power contracts would be based on the avoided cost of electricity to the purchasing utility. The 1978 Public Utility Regulatory Policies Act (PURPA) defines the avoided cost as "the incremental costs to an electric utility of electric energy or capacity or both, which, but for the purchase from the qualifying facility or qualifying facilities would generate itself or purchase from another source."(2)

The avoided cost to a utility purchasing CRRBP power would always include the marginal costs to produce power displaced by CRRBP. However, in order for capital costs to be included in the calculation of "avoided costs", two criteria must be met:

1. CRRBP power must be supplied on a firm (non-interruptible) contract basis; and,
2. the client utility must avoid the construction of new baseload capacity because of a power contract with CRRBP.

Since CRBRP is not being built by a utility to serve its own baseload power requirements, it is logical to market CRBRP power on a firm contract basis. Unlike a utility which must serve its own needs first, CRBRP power would not be interrupted to serve local demand. Therefore, if a client utility has a need of new baseload capacity after CRBRP becomes critical, and avoids constructing that capacity because of CRBRP, the avoided cost of CRBRP electricity is equivalent to the revenue requirements (per KWhr) of the baseload plant which was cancelled or deferred in lieu of a CRBRP power contract. Therefore, the following two questions were answered in order to estimate CRBRP project revenues:

1. Do utilities in the CRBRP market area require new baseload capacity in the 1991-1995 time frame? (Section II)
2. What are the revenue requirements per KWhr of the new baseload capacity required by the utilities? (Section III)

II. NEED FOR NEW BASELOAD CAPACITY.

The market area for CRBRP power is defined by the area over which CRBRP power can be efficiently transmitted. This area includes Tennessee, Kentucky, Mississippi, Alabama, Georgia, the Carolinas and most of Virginia. This area is roughly equivalent to service area of all of the utilities participating in the Southeastern Electric Reliability Council (SERC). SERC includes Tennessee, the Carolinas, Alabama, Georgia, Florida, and portions of Virginia, Kentucky and Mississippi. Since SERC provides forecasts of electrical generating capacity, the SERC region minus Florida was defined as CRBRP's market area. It was for this region that the analysis of the supply and demand of baseload capacity was performed.

The need for new baseload capacity depends on three variables:

1. reserve margin
2. projected capacity; and,
3. projected peak demand.

II.1. Reserve Margin

The reserve margin represents the difference, expressed as a percentage, between capacity and peak demand. Utilities have generally planned their capacity to exceed projected peak demand by about 20%. This allows for the fact that not all capacity can be expected to operate during periods of peak demand.

11.2. Projected Capacity

SERC member utilities have provided their own estimates of their future generating capacity to the North American Electric Reliability Council - reference 2). These projections account for existing capacity, expected retirements of existing capacity, and expected additions to existing capacity. For the purposes of this study, we also divided the expected additions into two categories: "firm" and "planned". Expected additions to capacity were considered "firm" if the planned units were under construction or, in the case of nuclear powerplants, if the unit were more than 10% complete. Expected additions to capacity that were not under construction (or more than 10% complete if nuclear) were regarded as "planned" capacity.

Planned capacity can be deferred or cancelled by a utility. A utility would do so if an economically attractive alternative existed, such as a firm power supply contract with CRBRP. The price at which CRBRP power would be economically attractive is analyzed below in Section III.

The SERC utilities have forecasted that in 1990 the installed generating capacity (summer) will be 153,320 MWe (reference 2, page 61, Table 208). Of this expected capacity, there are 13 powerplants which are "planned" capacity as opposed to "firm" capacity (see Table 1). These plants represent 8,322 MWe of capacity which would reduce SERC's "firm" capacity in 1990 to 144,998 MWe. Additional projected SERC capacity beyond 1990 is all "planned". In 1995 SERC's firm capacity remains at or below 144,998. Because Florida is outside the CRBRP market area, it was assumed that all of the planned power plants in Florida were not deferrable because of CRBRP. Therefore, these plants were moved from the "planned" category to the "firm" category. This increases the "firm" 1995 capacity in SERC to 149,113 MWe.

11.3. Projected Peak Demand

SERC projects 1995 for a peak demand of 141,841 MWe (reference 2, page 12, Table 38). In order to serve this projected capacity with a 20% reserve margin, approximately 16,000 MWe of additional capacity (excluding Florida) will be required. (See Appendix A for documentation of this calculation.)

It is well recognized that electricity demand forecasts have been revised downward over the last several years. It is also recognized that econometric models are not capable of predicting the underlying structural changes in the use of electricity. These changes, such as improved end-use efficiency, are largely responsible for the need to reevaluate electricity demand forecasts. In order to evaluate the impact of these factors on the required incremental baseload capacity in the CRBRP market area, the Oak Ridge National Laboratory has provided an assessment of power needs in this service area.(3) Two models were employed by ORNL. One model was econometric, while the other model was an integrated end use model. The latter model is explicitly sensitive to the structural changes which have resulted in lower electric power demand forecasts.

The models provided forecasts for a geographic area roughly equivalent to the SERC market area. Four sets of input assumptions were used. These input assumptions correspond to low, medium, and high world oil price cases and to a Southern Regional Growth Case. See reference 3 for details. The range of forecasted peak electricity demand for the SERC market area in 1995 was 143,000-153,000 MWe from the structural end use model and 194,000-203,000 MWe from the econometric model (see Table 1). The lowest forecast (143,000 MWe) is slightly higher than the recent SERC forecast discussed above (141,841 MWe). Therefore, our independent analysis of the need for power indicates that at least 17,000 MWe of additional capacity will be required to serve SERC in 1995 with a 20 percent reserve capacity (excluding Florida). If the highest forecast from the structural and use model were used, 27,000 MWe of capacity would be required by 1995. The econometric model forecasts imply much higher required capacities.

The power provided by CRBRP represents only 2% of the lowest forecast of required new generating capacity for the SERC region (minus Florida) in 1995. The required accuracy of this forecast is therefore much less than normal. Variations of several thousands of watts of capacity would still not alter the conclusion that some new generating capacity is available for displacement by CRBRP power. For example, if the forecast of required new capacity were reduced from 16 gigawatts to 4 gigawatts, a 25% reduction, CRBRP would still only displace 8% of 4 gigawatts of planned capacity.

In order to provide a completely independent assessment of the need for capacity question, the S.M. Stoller Corporation interviewed 25 utilities in or near the CRBRP market area. Over half of the utilities surveyed indicated that they would have to build new electrical generating capacity by 1993 in order to maintain a 20% reserve margin. Most utilities also envision the development of new capacity during the mid-90's.(4) The survey also revealed that "if power from CRBRP were to be contracted on a firm, base-load basis, the avoided new capacity cost would in all probability be for a coal plant."(4) Therefore, in the next section the most efficient coal fired base-load plant was used to estimate the least expensive electrical generating capacity available to utilities in CRBRP's market area.

III. AVOIDED COST OF NEW BASELOAD ELECTRICAL GENERATING CAPACITY.

CRBRP's economic value depends on the net revenue it can generate as a base-load electrical power station. The price at which CRBRP electricity can be sold is a major factor in determining CRBRP's economic (as opposed to its R&D) value. In order to estimate this price, the avoided cost of alternative new baseload capacity was estimated. In order to select an efficient alternative, a relatively large twin 600 MWe coal fired station (1200 MWe total) was selected as a basis for estimating avoided costs. The plant was assumed to go on line in 1991 in the Atlanta, Georgia area. The capital cost of this station is estimated to be \$1250/MWe (1984 \$ - see reference 5). If this plant investment were prorated to a 330 MWe plant (equivalent to CRBRP) an alternative coal fired facility would require a \$413 million (1984 \$)

investment. However, the capital cost of a 350 MWe coal plant (going on line in 1991) is \$584 million.(5) Therefore, if the revenue requirements of a large 1200 MWe coal station were used to negotiate CRBRP power contracts, utilities would have the opportunity to purchase smaller increments of base-load capacity (30 to 330 MWe) at the same cost per MWe as provided by a 1200 MWe plant. This provides a substantial benefit to many utilities since they may avoid construction of less economic units, under utilization of larger units, joint development of larger plants with other utilities, or periods of inadequate reserve capacity. This economic advantage is particularly beneficial to smaller utilities such as municipal utilities.

The methodology used to forecast the avoided cost of an alternative coal fired power plant is based on the revenue requirements method. Revenue requirements methods are used by public utilities and public utility commissions for rate-making purposes and are used by utilities to evaluate alternative projects. The Oak Ridge National Laboratory used the revenue requirements methodology with the normalized accounting method to estimate the avoided cost of a large coal fired power station.(5) The "reference" plant for which the avoided cost was estimated was a twin 600 MWe coal fired station. It had an assumed plant economic life of 30 years. It was assumed that the inflation rate would be 6% and that the escalation rate in excess of inflation for power plant construction would be 2%. The capitalization assumed for the plant was 51% debt, 12% preferred stock and 37% equity. The required rates of return on debt, preferred stock and equity were 10%, 10% and 15% respectively yielding an average interest of 11.9%.(5)

The plant location is assumed to be located in the Atlanta, Georgia area. The anticipated start up date is 1991. Using a reference data table developed by the United Engineers and Constructors for the Energy Economic Data Base Program, Phase V, (in addition to the above mentioned data and assumptions), the ORNL staff estimated that \$2.4 billion (nominal) would be expended on the reference plant resulting in a capital cost per KWe of capacity of \$2000 (or \$1250 in 1984 \$). Coal costs were derived from data provided by the Energy Information Administration. Two cases were derived: a low coal cost case of \$2.90/MBtu delivered (1982 \$) with no real cost escalation, and a high coal cost case of \$2.90/MBtu delivered (1982 \$) with a real cost escalation of 2%/year. For the purposes of the CRBRP avoided cost analysis, the low coal cost case was selected in order to develop a consistently conservative estimate of project revenues. The remaining revenue requirements data concerns the non-fuel operating and maintenance expenditures and the assumed capacity factor. An ORNL report (6) provided the O&M cost data and a 65% capacity estimate reflects current operating experience with large coal plants.

The resulting revenue requirements forecast is shown in Table 3. During 1991 a revenue requirement of \$146 /MWhr is estimated (nominal dollars - \$97 in 1984 \$). This increases to \$374/MWhr by 2020. The rate of increase is substantially lower than the assumed rate of inflation (3.2% versus 6.0%). This reflects the variable capital expenses which gradually decline over the economic life of the plant to zero after 2020 (full amortization). Another way

of expressing the cost per MWhr of electricity over the life of the plant is the levelized cost. The levelized cost does not decrease in real terms as do the revenue requirements but instead remains at a constant (or level) real value over the life of the plant. It is calculated by determining the present value (in 1991) of the revenue requirements from 1991 through 2020 and calculating a constant real annual payment which has an equivalent value to the present value estimated for 1991. The levelized cost equivalent to the revenue requirements estimated for this plant is \$54.50/MWhr (1982 \$). While the levelized cost is not a measure of the price electricity will be sold in any particular year, it does provide a single measure of the average cost of electricity over the life of the plant. As such, it is often used to compare among alternative power plant investments or to compare alternative cost estimates of a given type of power plant capacity.

The ORNL developed levelized cost estimate was compared to three other studies of the cost of a large coal fired power station (7, 8 and 9). As we might expect, the studies were not directly comparable. Differences in the assumed start up dates, location, cost of money and tax law made direct comparison of the results somewhat misleading. In order to demonstrate the effects of all of these factors and to determine a relevant comparison, ORNL used alternative assumptions which correspond to those used in each of the three alternative studies. For example, in Table 4, the ORNL/CRBRP results are compared to those of the Energy Information Administration.(7) In the first column of Table 4 the estimated levelized cost for capital, O&M, fuel and total are shown as derived by EIA. The ORNL/CRBRP results are shown in column 2 as reported (5). It first appears that the ORNL/CRBRP levelized cost is significantly higher (54.5 mills/KWhr versus 44.1 mills/KWhr). However, most of this difference disappears when the ORNL/CRBRP levelized cost is also expressed in 1980 \$ (46.2 mills versus 44.1 mills). The difference is further reduced when the start up year, cost of money, inflation rate and tax law (old 1981 tax law instead of new 1982 tax law) are changed to correspond to EIA's analysis. The resulting difference (44.1 mill \$/KWhr from EIA versus 45.2 mills/KWhr from ORNL (CRBRP) is within 3% (see Table 4). A similar comparison shows that the ORNL/CRBRP results are quite similar to those derived by Brandfon (within 1%) and Perl (within 7%) -- see Tables 5 and 6.

It can, therefore, be concluded that the avoided cost projections presented in Table 3 represent a conservative estimate of the price at which CRBRP power can be sold. The prices represent the payment for electricity at the client utility rather than CRBRP's busbar. Therefore, any wheeling charges and transmission losses have to be explicitly accounted for when determining the cash flows associated with CRBRP operation. Sufficient wheeling capacity is available for CRBRP power via TVA and presents no constraint to the sale of CRBRP power except for the one or two mills per KWhr that is typically charged for such services.(3) The wheeling losses are in the order of 3% for each utility that CRBRP power must be transmitted.

TABLE 1

LIST OF SERC BASELOAD POWERPLANTS WHICH ARE PLANNED (COAL) OR LESS THAN 10% COMPLETE (NUCLEAR)

POWERPLANT NAME	UNIT SIZE	REGION	SUBREGION	STATE	FIRM	FUEL TYPE	UNIT STATUS	PROJECTED SERVICE DATE
St. Johns River 1	550 MW	SERC	Florida	Florida	JACO	Bituminous	Planned	85/12
Stanton 1	415 MW	SERC	Florida	Florida	ORLA	Bituminous	Planned	86/11
St. Johns River 2	550 MW	SERC	Florida	Florida	JACO	Bituminous	Planned	87/06
Taylor 1	600 MW	SERC	Florida	Florida	SECI	Bituminous	Planned	88/06
Martin 3	700 MW	SERC	Florida	Florida	FLPL	Bituminous	Planned	89/xx
Taylor 2	600 MW	SERC	Florida	Florida	SECI	Bituminous	Planned	90/01
Martin 4	700 MW	SERC	Florida	Florida	FLPL	Bituminous	Planned	90/xx
Vogtle 2	1,150 MW	SERC	Southern	Georgia	GEPC	Uranium	8% Complete	88/09
Unnamed Lignite	250 MW	SERC	Southern	Mississippi	SOMI	Lignite	Planned	90/04
Cross Site Unit 1	450 MW	SERC	VACAR	S. Carolina	SOCa	Bituminous	Planned	88/06
Harris 2	900 MW	SERC	VACAR	N. Carolina	CAPO	Uranium	4% Complete	89/03
Undetermined 1	550 MW	SERC	VACAR	S. Carolina	SOCG	Coal	Planned	89/05
North Anna 3*	907 MW	SERC	VACAR	Virginia	VIEP	Uranium	8% Complete	89/10

*North Anna 3 has been canceled.

TABLE 2

1995 FORECASTED PEAK ELECTRICITY DEMAND FOR SERC MARKET AREA (MW_e)

CASE	STRUCTURAL USE MODEL	ECONOMETRIC MODEL	CURRENTLY PLANNED** FIRM CAPACITY	REQUIRED NEW CAPACITY IMPLIED BY STRUCTURAL END USE MODEL*	REQUIRED NEW CAPACITY IMPLIED BY ECONOMETRIC MODEL
Low World Oil Price	142,936	194,099	149,113	17,480	65,369
Medium World Oil Price	147,227	194,435	149,113	21,496	65,683
High World Oil Price	149,775	194,581	149,113	23,881	65,820
Southern Regional Growth Case	153,009	203,233	149,113	26,908	73,918

SOURCE: Oak Ridge National Laboratory, "Initial Phase Draft Report, Clinch River Breeder Reactor, Assessment of Need for Power and Service Area," February 28, 1983, Letter from D.M. Hamblin to D.C. Keeton, dated March 2, 1983, and North America Reliability Councils Electric Power Supply and Demand (1982-1991), August 1982.

* Required to maintain a reserve capacity of 20 percent, Florida excluded.

** Assumes currently planned capacity in Florida is firm. All currently planned capacity (except Florida) that is not yet under construction or is less than 10 percent complete (nuclear only) is assumed not to be firm capacity.

TABLE 3

CRBRP ELECTRICITY PRICE PROJECTION:
 AVOIDED ENERGY AND CAPACITY COST OF ALTERNATIVE BASE LOAD POWER PLANT*

<u>YEAR</u>	<u>\$/MWhr</u> <u>(YEAR OF EXPENDITURE)</u>
1991	146
1995	151
2000	165
2005	189
2010	231
2015	292
2020	374
Levelized Cost (1982 \$/MWhr)**	54.50

* Twin 600 MWe coal fired power plants with 1991 startup - low coal cost case.

** The levelized cost is derived by totaling the present value in 1991 of the annual revenue requirements (through 2020) and applying the capital recovery factor. This estimate is expressed in constant 1982 dollars.

SOURCE: J.G. Delene, G.R. Smolen and H.I. Bowers, Engineering Economic Analysis of Utility Alternatives to the Clinch River Breeder Reactor, Oak Ridge National Laboratory, March 1, 1983.

TABLE 4

COMPARISON OF CRBRP AND EIA
LEVELIZED COST ANALYSIS FOR COAL FIRED POWER PLANTS

Mills/KWhr						
	EIA (1980 \$)	CRBRP (1982 \$)	CRBRP (1980 \$)	CRBRP MOD 1 (1980 \$)	CRBRP MOD 2 (1980 \$)	CRBRP MOD 3 (1980 \$)
Capital	16.6	20.3	17.3	18.6	15.8	15.3
O&M	5.3	5.4	4.5	4.5	4.5	4.5
Fuel	22.2	28.7	24.4	25.4	25.4	25.4
Total	<u>44.1</u>	54.5	46.2	48.5	45.7	<u>45.2</u>

Column 1 Levelized cost as reported for region 4 in EIA Report.

Column 2 Levelized cost as reported for CRBRP avoided cost analysis.

Column 3 CRBRP levelized cost expressed in 1980 \$ (18% inflation 1980 to 1982).

Column 4 Mod 1: CRBRP alternative moved from 1991 startup to 1995 startup (as in EIA Report).

Column 5 Mod 2: Mod 1 plus use of EIA cost of money and inflation assumptions.

Column 6 Mod 3: Mod 1 plus Mod 2 plus use of old 1981 tax law instead of new 1982 tax law (affects depreciation schedule and investment tax credit).

SOURCES: U. S. Department of Energy, Energy Information Administration, Projected Costs of Electricity from Nuclear and Coal-Fired Plants DOE/EIA-0352, August 1982.

J. G. Delene, et al, unpublished report, March 1983 (forthcoming).

TABLE 5

COMPARISON OF CRBRP AND W. W. BRANDFON
LEVELIZED COST ANALYSIS FOR COAL FIRED POWER PLANTS

	Mills/KWhr			
	BRANDFON REPORT (NOMINAL \$)	CRBRP (1982 \$)	CRBRP MOD 1 (1982 \$)	CRBRP MOD 1 (NOMINAL \$)
Capital	89	20.3	23.2	97
O&M	37	5.4	5.4	22
Fuel	86	28.7	22.4	92
Total	<u>212</u>	54.5	51.0	<u>211</u>

Column 1 Levelized cost as reported by W. W. Brandfon.

Column 2 Levelized cost as reported for CRBRP avoided cost analysis.

Column 3 Mod 1: CRBRP alternative moved from 1991 startup to 1995 startup and moved from Southeastern U. S. to Midwest.

Column 4 Mod 1 results expressed in nominal dollars (as are Brandfon's estimates).

SOURCES: W. W. Brandfon, "A Comparison of Future and Coal-Fired Electric Generation in Midwestern United States", ANS Winter Meeting, Washington, D.C., November 18, 1982.

J. G. Delene, et al, unpublished report, March 1983 (forthcoming).

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TABLE 6

COMPARISON OF CRBRP AND L. W. PERL
LEVELIZED COST ANALYSIS FOR COAL FIRED POWER PLANTS

	Mills/KWhr					
	PERL REPORT (1982 \$)	CRBRP (1982 \$)	CRBRP MOD 1 (1982 \$)	CRBRP MOD 2 (1982 \$)	CRBRP MOD 3 (1982 \$)	CRBRP MOD 4 (1982 \$)
Capital	11.7	20.3	17.9	15.3	13.4	12.4
O&M	3.1	5.4	5.4	5.4	4.4	4.4
Fuel	23.0	28.7	24.7	24.7	23.7	23.7
Total	<u>37.8</u>	54.5	48.0	45.4	41.4	<u>40.5</u>

Column 1 Levelized cost as reported by C. W. Perl.

Column 2 Levelized cost as reported for CRBRP avoided cost analysis.

Column 3 Mod 1: CRBRP alternative moved from 1991 startup to 1985 startup.

Column 4 Mod 2: Mod 1 plus Perl's cost of money and inflation assumptions.

Column 5 Mod 3: Mod 1 plus Mod 2 plus Perl's capital cost, plant capacity factor and coal cost estimates. O&M costs were also adjusted to low sulfur coal.

Column 6 Mod 4: Mods 1 through 3 plus an assumed 10 year tax life and use of 1981 tax law instead of 1982 tax law.

SOURCES: Lewis J. Perl, "The Economics of Nuclear Power," 1982 Annual Conference of the Atomic Industrial Forum, November 15, 1982.

J. G. Delene, et al, unpublished report, March 1983 (forthcoming).

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2. North American Electric Reliability Council, Electric Power Supply and Demand, 1982-1991, Annual Data Summary Report for the Regional Reliability Councils of NERC, August 1982.
3. Oak Ridge National Laboratory, "Initial Phase Draft Report, Clinch River Breeder Reactor: Assessment of Need for Power and Service Area," February 28, 1983.
4. S. M. Stoller Corporation, "Projections of Revenues from CRBRP Operation and CRBRP Investment Analysis," Appendix ("Results of the Utility Survey for Data on Factors Which Influence the Market Potential of CRBRP Electricity"), March 1983.
5. J. G. Delene, G.R. Sanders, H.I. Bowers, Engineering Economic Analysis of Utility Alternatives to the Clinch River Breeder Reactor, Oak Ridge National Laboratory, March 1, 1983.
6. U. S. Department of Energy, Energy Information Administration, Projected Costs of Electricity from Nuclear and Coal-Fired Plants, DOE/EIA-0352, August 1982.*
7. M. L. Myers, C.C. Fuller and H.I. Bowers, "Non-Fuel Operation and Maintenance Costs for Large Steam Electric Power Plants", ORNL/TM-8324, September 1981.
8. W. W. Brandfon, "A Comparison of Future and Coal-Fired Electric Generation in Mid-western United States", ANS Winter Meeting, Washington, D.C., November 18, 1982.
9. Louis J. Perl, "The Economics of Nuclear Power," 1982 Annual Conference of the Atomic Industrial Forum, November 15, 1982.

APPENDIX A

DOCUMENTATION OF REQUIRED NEW CAPACITY CALCULATIONS

A.1. Estimated "Firm" Capacity for 1995

1990 estimate of installed generating capacity for SERC (reference 2, page 61, Table 20S)	153,320 MWe
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Capacity included in above estimate which is outside of Florida for which construction has not begun or, if nuclear, is less than 10% complete ("planned" capacity)	4,207 MWe
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1990 "Firm" Capacity for SERC	149,113 MWe
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"Firm" capacity in SERC 1990-1995	0
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1995 "Firm" Capacity for SERC	149,113 MWe
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A.2. Required New Capacity for 1995

RNC = 0.78 (1.2 FPD - 149,113 MWe)

where

RNC = Required new capacity in 1995

FPD = Forecasted summer peak demand in 1995

The factor 1.2 accounts for the assumed 20% reserve margin. The factor 0.78 accounts for Florida's share of the estimated required new capacity. This factor is based on SERC's estimated share of Florida's peak demand relative to SERC's peak demand of 22% (reference 2, page 12, Table 3S).



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May 24, 1983

TO : Honorable Gordon J. Humphrey
United States Senate

ATTENTION : Henry Sokalsky

FROM : Alvin Kaufman
Senior Specialist in Regulatory Economics

SUBJECT : Review of DOE Memorandum of April 14, 1983 entitled
"Documentation of Project Revenue Projections for CRBRP".

I have reviewed the April 14 memorandum. I find the assumptions reasonable, and methodology acceptable in that it is standard. The estimate of future demand in the SERC region is somewhat higher than our own, but given the small size of CRBRP, this differential is probably not important.

Of greater importance is the relevance of the avoided cost figure computed in the memo. DOE used the standard levelized cost methodology for a 1200 MW coal plant on-line in 1991. Thus the avoided cost (levelized cost, low coal cost case) in 1982 dollars was computed to be approximately 5.5 cents per Kwh. It seems to me that the avoided cost is dependent on what a utility feels it needs in the way of capacity. That is, if a utility will require 1200 MW in new capacity and can obtain 300 MW from CRBRP, it will still have to build 900 MW. Its avoided cost is the difference between building 1200 MW and 900 MW. Given that the cost of land requirements, coal handling facilities, overhead expenses, etc. would be similar whether 1200 or 900 MW were constructed at the same site it is likely that the cost of these different sized plants would be relatively close. Thus, it may well be that the avoided cost would be less than DOE computed.

The computation of the cost of a 900 MW vs a 1200 Mw plant at the same site probably requires the use of a relatively sophisticated model. Such a model is not available to us, but DOE may have access to one that could be used. The memo and draft report are returned herewith.

300 Chestnut Street Tower II

JUN 05 1981

Mr. Gordon Chipman
Room B
374 Rayburn HOB
Washington, DC 20515

Dear Mr. Chipman:

In response to your request for a determination of the "plant life revenues" of the Clinch River Breeder Reactor, we have prepared the following information.

Based on a 30-year life and beginning operation in 1990, the plant has been evaluated using the energy output levels provided us and listed below.

1990	146.25 MW-years
1991	187.5 MW-years
1992	225.0 MW-years
1993-2020	281.25 MW-years

We have also included the operating costs of \$544.5 million in the first five years of operation which were provided to us. Beyond the fifth year, we have used \$26.5 million (fuel) and \$15.0 million operation and maintenance expenses as provided to us. We have escalated these values at the appropriate escalation rate of 9.7 percent for fuel and 11.5 percent for operation and maintenance costs.

The enclosed table provides the detailed calculations in determining this plant life revenue. Since we do not estimate rates beyond 2000, general trends were observed to determine the level of wholesale rates beyond that year.

Using the 14-3/8-percent discount rate you requested, the 30-year net worth of generation from the Clinch River Breeder Reactor is approximately \$542 million (1981 dollars). For the initial five-year period of operation, this value is approximately \$63 million.

It should be noted that present contractual arrangements call for purchase of power from the Clinch River Project at the cost of generation displaced on the TVA system. This rate is generally lower than the wholesale rate.

If you have further questions, please let us know.

Sincerely,

Lynn C. Maxwell, Chief
Power Planning Staff

GPG:LHB

Enclosure

cc: ARMS, 640 CST2-C (Enclosure)

Clinch River Breeder Reactor

Year	Operating Value			Operating Costs Millions \$			Net Value Millions\$	Present Worth of Net Value 1981\$ @ 14.38%
	Wholesale Rate \$/MWh	Generation Millions kWh	Operating Benefits Millions \$	Fuel	O&M	Total		
1990	73.7	1281	94.4			108.9	-14.5	-4.3
1991	80.2	1643	131.8			108.9	22.9	5.0
1992	86.0	1971	169.5			108.9	60.6	13.8
1993	92.2	2464	227.2			108.9	118.3	23.6
1994	99.1	2464	244.2			108.9	135.3	23.6
1995	106.8	2464	263.2	26.5	15.0	41.5	221.5	33.8
1996	115.2	2464	283.9	29.1	16.7	45.8	238.1	31.8
1997	123.4	2464	304.1	31.9	18.6	50.5	253.6	29.6
1998	132.6	2464	326.7	35.0	20.8	55.8	270.9	27.6
1999	142.6	2464	351.4	38.4	23.2	61.6	289.8	25.8
2000	153.7	2464	378.7	42.1	25.9	68.0	310.7	24.2
2001	166.8	2464	411.0	46.2	28.8	75.0	336.0	22.9
2002	181.6	2464	447.5	50.7	32.1	82.8	364.7	21.7
2003	198.0	2464	487.9	55.6	35.8	91.4	396.5	20.7
2004	216.3	2464	533.0	61.0	40.0	101.0	432.0	19.7
2005	236.6	2464	583.0	66.9	44.5	111.4	471.6	18.8
2006	259.4	2464	639.2	73.4	49.7	123.1	516.1	18.0
2007	284.8	2464	701.7	80.5	55.4	135.9	565.8	17.2
2008	313.3	2464	772.0	88.3	61.8	150.1	621.9	16.6
2009	345.3	2464	850.8	96.9	68.9	165.8	685.0	15.9
2010	379.9	2464	936.1	106.3	76.8	183.1	753.0	15.3
2011	416.0	2464	1025.0	116.6	85.6	202.2	822.8	14.6
2012	455.5	2464	1122.4	127.9	95.4	223.3	899.1	14.0
2013	498.8	2464	1229.0	140.3	106.4	246.7	982.3	13.4
2014	546.2	2464	1345.8	153.9	118.7	272.6	1073.2	12.8
2015	598.1	2464	1473.7	168.8	132.3	301.1	1172.6	12.2
2016	654.9	2464	1613.7	185.2	147.5	332.7	1281.0	11.6
2017	717.1	2464	1766.9	203.1	164.5	367.6	1399.3	11.1
2018	785.2	2464	1934.7	222.8	183.4	406.2	1528.5	10.6
2019	859.8	2464	2118.5	244.5	204.5	449.0	1669.5	10.1
2020	941.5	2464	2319.9	268.2	228.0	496.2	1823.7	9.7
30-year sum							19701.8	542.4

TENNESSEE VALLEY AUTHORITY

CHAITANOOGA TENNESSEE 37401
300 Chestnut Street Tower II

May 23, 1983

Mr. Henry Sokolski
Office of Senator Gordon J. Humphrey
United States Senate
Room No. SH-531
Washington, D.C. 20515

Dear Mr. Sokolski:

This is in response to your question about the year in which the value of the Clinch River Breeder Reactor Project (CRBRP) is stated in the Breeder Reactor Corporation's task force report entitled "Exploration of Alternative Financing Possibilities For The Clinch River Breeder Reactor Project."

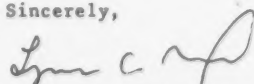
The \$1 billion figure quoted in the task force report is for an investment in 1992 dollars. This figure is based on the revenues or proceeds from selling the output of the CRBRP for a 20-year period beginning in 1992 at a price equivalent to cost of power from a new coal-fired plant. We have reviewed the estimates of the cost of capital, fuel, operation and maintenance which formed the basis of the cost of power from a new coal-fired plant, and those estimates involve assumptions generally consistent with those used by TVA.

In my letter to Gordon Chipman dated June 5, 1981, TVA calculated a net plant life revenue figure for the CRBRP based on a format and information provided by Mr. Chipman. For purposes of this calculation, Mr. Chipman asked that we use as the revenue stream for the CRBRP a projection of TVA total system revenue requirements per kilowatthour reduced to present value in 1981. The average TVA system revenues are based upon the Nation's largest electric power system consisting of a variety of production facilities built over a 50-year period, including hydro, coal, nuclear, and pumped-storage facilities. These have greatly differing capital and operating costs. Average system revenues are thus entirely different from the incremental costs (or value) of a new plant being added to an existing system. Accordingly, the \$542 million figure derived from the 1981 calculation cannot be properly compared with the \$1 billion stated in the task force report.

Since the projected costs of operating the breeder and the assumed generation from the breeder appear to have changed since the time of the 1981 calculation, it would be difficult for TVA to update the calculations as you suggested.

If you have any further questions, please do not hesitate to call me.

Sincerely,



Lynn C. Maxwell, Chief
Power Planning Staff

Report No. 82-147 S

DO WE REALLY NEED ALL THOSE ELECTRIC PLANTS?

By

Alvin Kaufman
Senior Specialist in
Mineral and Regulatory Economics

and

Karen K. Nelson
Research Assistant in
Mineral and Regulatory Economics

[The following is excerpted from the above named report.]

August 1982

TC 147 U.S. C

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SUMMARY

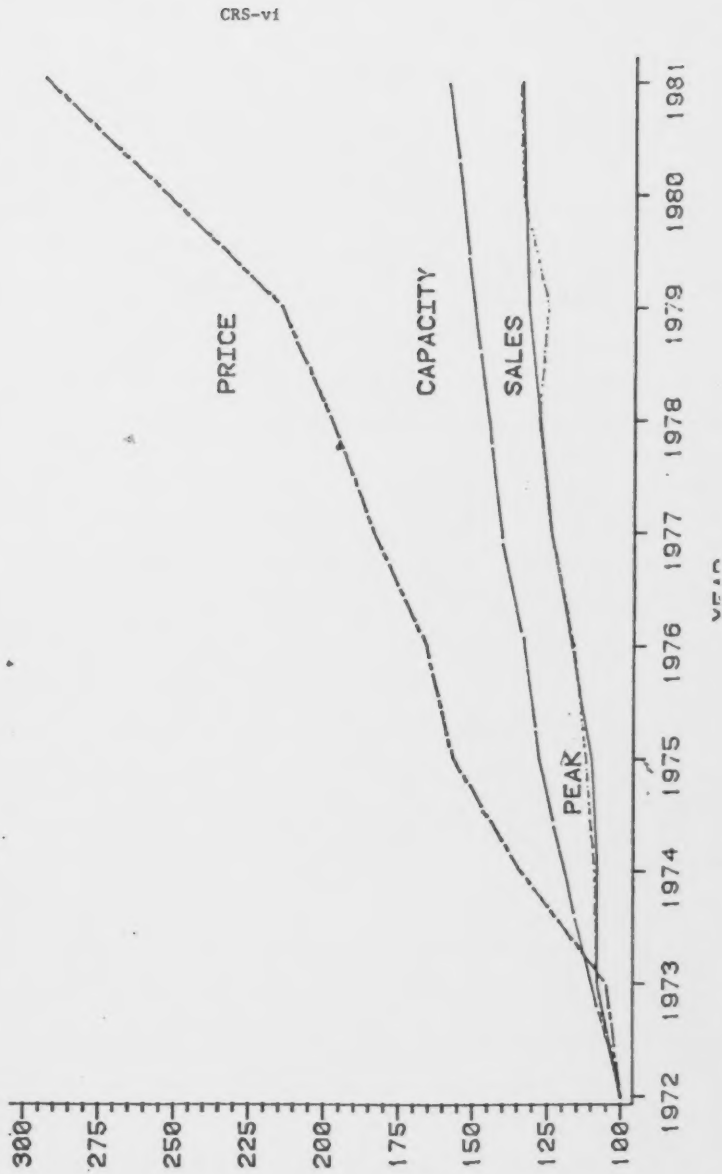
Electricity is likely to become an increasingly important energy option over the next 20 years in the United States. The magnitude of electric demand growth, however, is extremely uncertain and dependent on numerous social, as well as economic, trends. Given the importance of electricity to economic growth and to the public health and safety, it is important to assure adequate supplies. As a consequence, capacity planning becomes very difficult, given the long lead times required between perception of need and production of electricity.

The uncertainty problem is compounded by the somewhat tenuous financial condition of the utility companies. This adds to the problems associated with planning and construction of new capacity. Much of the industry's current financial problems have been brought on by slowing demand for electricity combined with rising construction and fuel costs. Electric demand growth rates have fallen sharply since the early 1970s. Sales of electricity in 1981 increased less than 1 percent over the previous year (Figure 1). At the same time, busbar costs increased by almost 3-1/2 times in real terms in the past decade to the point where busbar costs in 1980 exceeded the average price of electricity sold to end users. In comparison to other energy sources electric prices rose slower, and electric use increased 25 percent between 1973 and 1980, versus a 17 percent decrease in demand for nonelectric energy sources. This relatively stronger growth trend for electricity is expected to continue in the future.

Financially, the utilities have been facing difficulties in recent years in attracting investments, maintaining earnings, and fulfilling construction plans. Operating revenues have increased, but costs have risen relatively faster. The poor performance of utility profitability and common stock prices

ELECTRIC UTILITY SALES AND CAPACITY, 1972-1981

INDEX: 1972=100



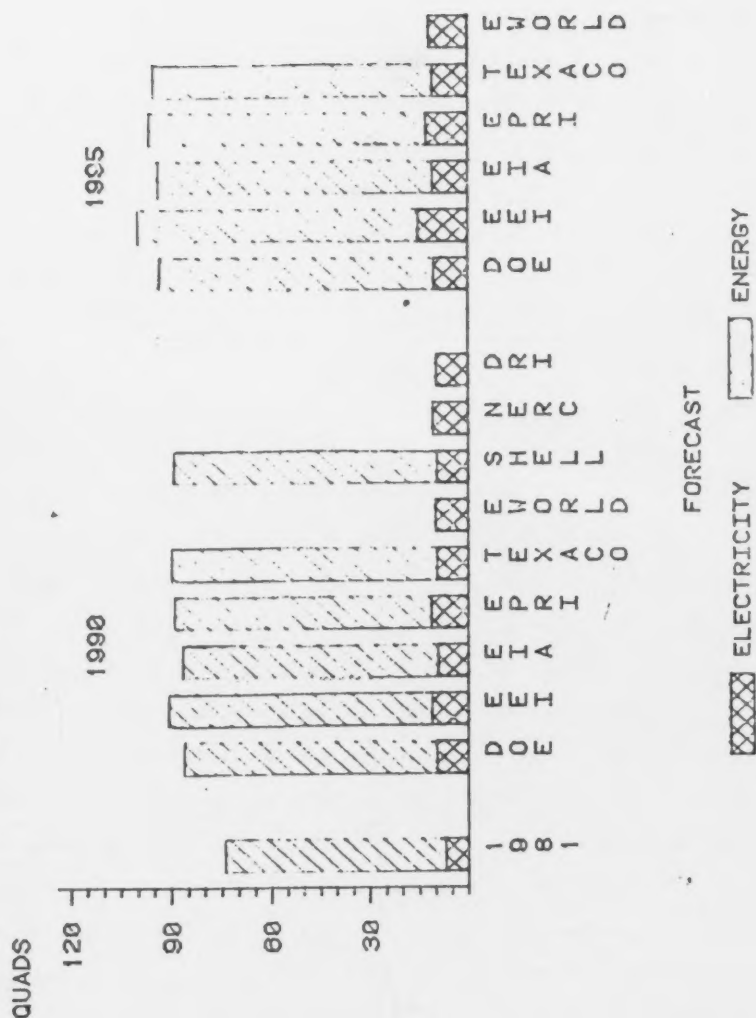
and returns that have been characteristic of the last decade have begun to show some upward signs in the last year and a half. Common stock earnings and return on equity have improved dramatically recently.

Despite recent financial hardships that may have slowed utility expansion, the unexpected decline in electric demand growth has left the utility industry with excess capacity on a national average, with generating reserves at 31 percent in 1980. In terms of reliability assurance, this level is more than adequate. New generation, especially nuclear plants, are being deferred as much as possible within what appear to be prudent limits.

Forecasts of electric demand through the end of the century indicate that this reaction to declining demand may be appropriate. Although forecast methodology and assumptions affect predictions, forecasters see growth in electric demand ranging from 2.6 to 3.7 percent between 1980 and 1990 and from 2.5 to 5.4 percent between 1990 and 2000 (Figure 2). Forecasts for growth in demand for all energy range from 0.9 percent to 1.2 percent between now and 1990, about half of what it was in the 1960s and early 1970s. The future state of the economy is the primary variable behind the forecasts. Other factors such as projected fuel and electricity prices, assumed levels of conservation, changing fuel use practices and demographics will also have a bearing.

For the purposes of the CRS forecast presented in this paper, we rely on economic growth and the price of electricity as electric demand level determinants, both having shown high correlation factors to electric demand. This relationship is also illustrated by the close fit in using the model on historic data. Three different growth and price assumptions were used. GNP was taken at 2 percent, 3 percent, and 4 percent growth per year, based on the lowest assumption used in the forecasts discussed earlier, and on the projections

FORECASTS OF ENERGY AND ELECTRIC CONSUMPTION 1990 AND 1995



contained in the Economic Report of the President. The 3 percent growth assumption was selected because many scholars believe this to be the minimum growth required for full employment.

The price assumptions vary from no increase, except for inflation, to a rate 5 percent above inflation. The stable real price assumption permits testing of the economic growth variable alone. It is based on the assumption that regulators will not permit price increases beyond the general inflation rate due to public pressure. The high estimate assumes rapid escalation in construction and fuel costs. The middle price estimate is derived from the assumptions used in the forecasts by others discussed earlier. It assumes moderate real increases in fuel and construction costs.

In any case, based on these scenarios the high estimate for electric demand can be taken as 4 percent GNP, 0 percent price giving a sales growth of 4.3 percent per year, while the low estimate is 2 percent GNP, 5 percent price giving a growth of 2 percent. Between this band of 2.0 to 4.3 percent growth per year in electricity sales, we have selected 3 percent GNP, 2 percent price giving a 3.2 percent per year electric growth as our midlevel estimate.

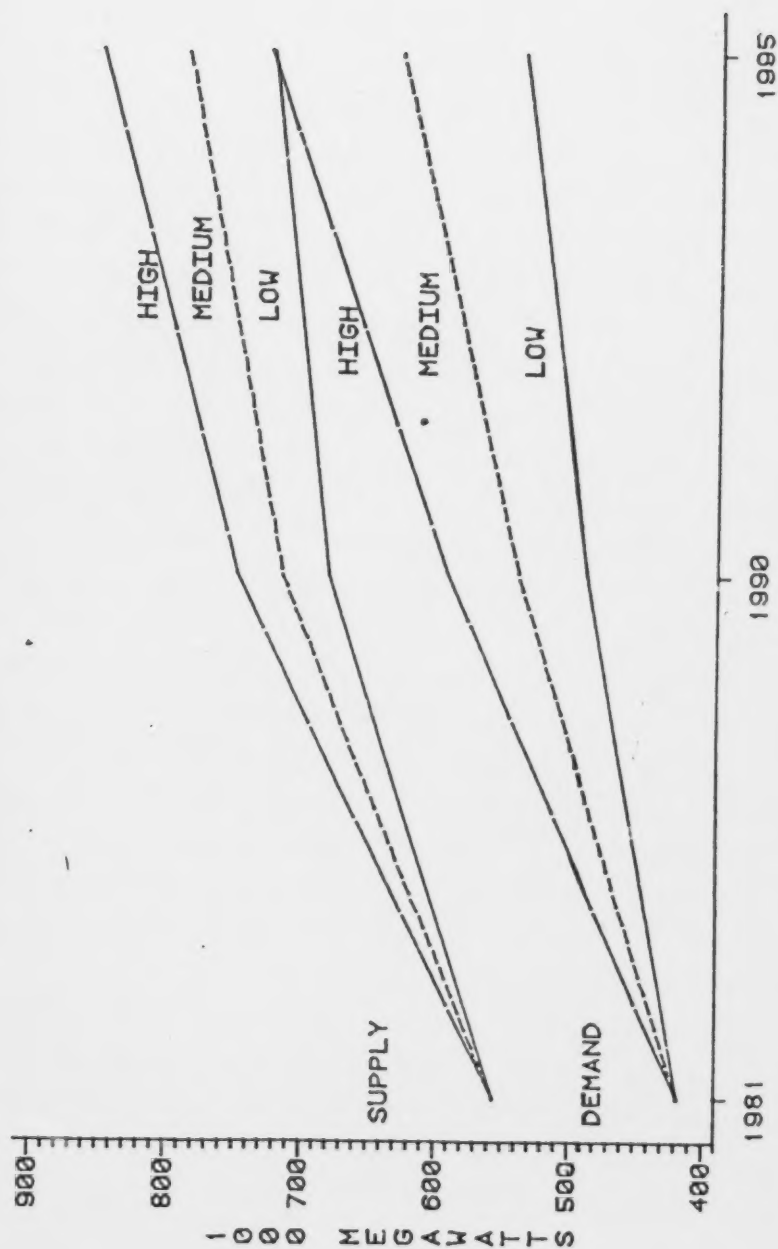
These sales estimates were then converted into peak load assuming a 7 percent loss and a 63.4 percent load factor. The latter is a forecast by the North American Electric Reliability Council (NERC). These estimates are shown in figure 3.

The uncertainties in electric demand estimates are equalled in capacity planning. Financial pressures, new plant siting problems, and long required lead times for construction compound the risk and uncertainty. The results have been a decline in planned additions to capacity and shifts in the type of plant proposed for construction, from fewer nuclear to more fossil steam plants.

SUPPLY AND DEMAND FOR ELECTRICITY 1981-1995

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Given these difficulties, we have selected the NERC planned capacity as our high estimate, and derived a low estimate by postulating delays based on the status of the unit. The middle case was computed as an average of the high and low (Figure 3).

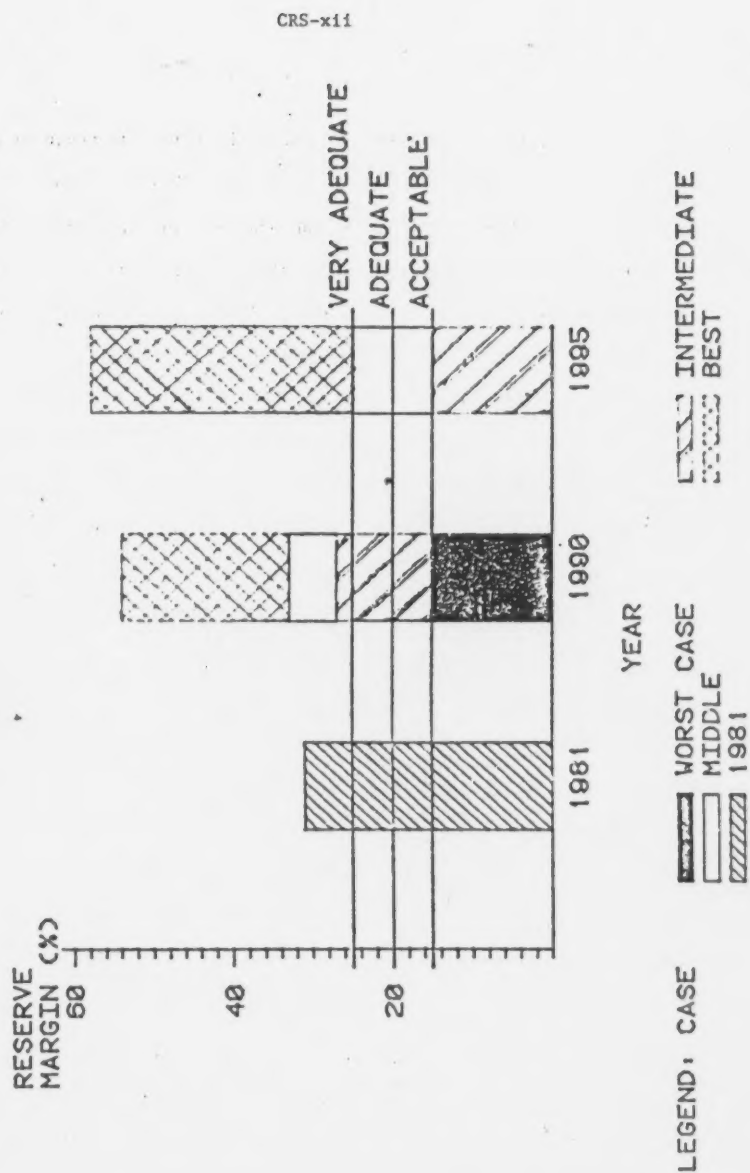
The figure indicates that capacity will be less than demand in only one case, and that in 1995. In all other instances capacity exceeds demand. The adequacy of capacity in relation to demand, however, cannot be judged without considering the reliability of the system. That is, every system must maintain a certain quantity of surplus capacity to guard against outages, maintenance requirements, etc. This redundancy or reserve margin required to guard the reliability of the system is usually taken as optimal at 20 percent of the peak load, with 15 percent generally taken as the lower limit of an acceptable range.

In an effort to test the ability of the utility industry to meet future demand, four scenarios have been postulated based on the demand and supply cases discussed earlier. These include a worst case derived by assuming high demand and our worst capacity case, a best case derived from our low demand and best capacity case, and a middle case using the middle capacity and supply cases. The fourth case assumes our middle demand and the worst supply case. The results of these computations are shown in figure 4.

Our worst case will not have enough capacity to assure the reliability of the system by 1990 and indicates a serious shortfall by 1995. All of our other cases are well above 20 percent in 1990. The middle and best cases reserves are at least very adequate by 1995.

It would thus appear that serious reliability problems are likely only if the economy grows at 3 percent per year or better, and capacity construction follows our worst capacity assumptions. If the economy grew at 3 percent, but capacity was in our middle range, there would be no difficulties.

ESTIMATED RESERVE MARGINS, VARIOUS SCENARIOS 1981 TO 1985



In short, it is apparent that it is unlikely there will be capacity problems unless the economy experiences rather vibrant growth (4 percent GNP). At rates less than 4 percent, shortages are not likely except under the worst capacity case assumptions, and then only after 1990. There would be ample time to take corrective action as the direction of growth becomes clearer. It would thus appear that we do not need all of the contemplated capacity except in the case of high economic growth, and even there some slippage in construction schedules would be acceptable.

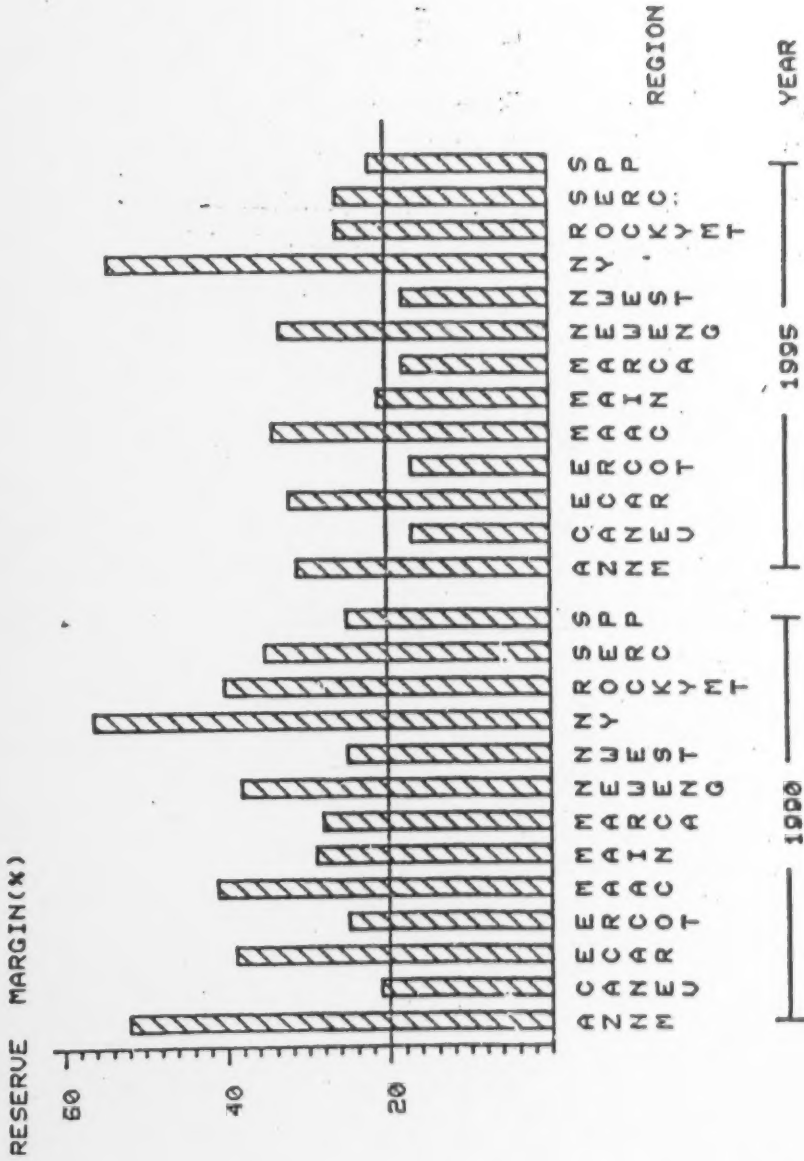
In any case, the discussion above deals with national aggregates. If the U.S. electric utilities were completely intertied in an economic dispatch system, such an analysis would be sufficient. The U.S. system is, however, a regional arrangement. As a consequence, national numbers may mask serious deficiencies in specific regions. Therefore, it may be useful to review the regional situation.

The regional peak demand forecasts, as shown in figure 5, were derived by allocating the medium case estimates among the power areas. Regional capacity forecasts were derived by computing a worst case for each and averaging this with the NERC estimate, resulting in a medium capacity case. Under these assumptions, none of the regions have inadequate reserves in 1990, with several areas severely overbuilt, particularly Arizona-New Mexico and New York. If a worst capacity case were assumed, the Electric Reliability Council of Texas (ERCOT) and the Southwest Power Pool (SPP) would fall between 15 and 20 percent reserves and only California-Nevada would be under 15 percent. By 1995 four areas are below 20 percent, but still at least 17 percent. In the worst case, however, only four areas would be above 20 percent reserves.

Thus, most areas of the country should be in good condition in terms of electric generating capacity by 1995 given a medium capacity case and moderate

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MARGINAL GENERATING RESERVES BY REGION, 1990 AND 1995



economic growth. The combination of demand uncertainty, a currently overbuilt system, and financial constraints has created caution in the industry regarding capacity additions. This is for the best, given the probable excess of plant

Because electric usage has such a far reaching effect and may have a detrimental effect on economic growth, the attention of Federal, as well as local, regulators and legislators is required. Insufficient reliability can threaten the public welfare, and problems in a single system can become widespread because of the numerous interties. As a result of these national considerations, the Congress has provided the utility industry with special incentives to stimulate construction and ease utility financial pain.

These include tax incentives such as accelerated depreciation, tax credit and tax free dividends if reinvested in utility stock.

Given the emerging realization that the industry may well be overbuilt, and may remain that way for some years to come, it may be necessary to reexamine Federal policies toward utilities and to consider alternative strategies for the industry.

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